RELIABILITY - CRITERIA AND PRACTICE

Submission of

ONTARIO HYDRO

to the

Royal Commission

On Electric Power Planning

with respect to the

Public Information Hearings

May, 1976

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3 | 10.1 | <u>INTRODUCTION</u>

Reliability is one of the major factors in the
planning, design, operation and maintenance of electric
power systems and must receive attention through the
full life cycle of planning any facility. It is
however, only one of the factors to be considered and
reliability standards therefore represent a compromise
with other factors such as safety, cost, availability
of capital and environmental constraints.

This memorandum discusses some general aspects of
reliability and then describes the practices and
criteria followed by Ontario Hydro in providing for
reliability in the generation and bulk power
transmission facilities.

10.1.1 | <u>Ontario Hydro System</u>

Today's generating system comprises 40 generating
stations from 10 MW to 2,431 MW in capacity and a
number of smaller stations. Most stations have several
generating units.

The bulk power transmission system comprises a network
of transmission lines at 500 kV, 230 kV or 115 kV,
connecting the generating stations to the load areas
and to each other, effectively integrating them into a
single system. The network includes several hundred
individual circuits. The complexity of this network is
illustrated in Figure 10-1, which shows the 500 kV and
230 kV lines in the southern section of Ontario Hydro's
East System.

The protection and control systems are an integral part
of the generating and transmission facilities and are
of major importance in determining system reliability.

10.2 | <u>DEFINITIONS AND GENERAL CONSIDERATIONS</u>

10.2.1 | <u>The Meaning of Reliability</u>

The reliability of an electric supply system may be
defined in general terms as the degree of continuity of
full electric power supply delivered to the user's
premises. Perfect reliability would mean that full
electric power supply is available 100% of the time,
i.e. 8,760 hours in a year.

SOUTHERN SECTION EAST SYSTEM
SCHEMATIC DIAGRAM OF 60HZ
500 & 230KV TRANSMISSION FACILITIES
DECEMBER·31·1975

FIGURE 10-1

SYSTEM PLANNING   MAR·1·1976   DWG·2912·SP
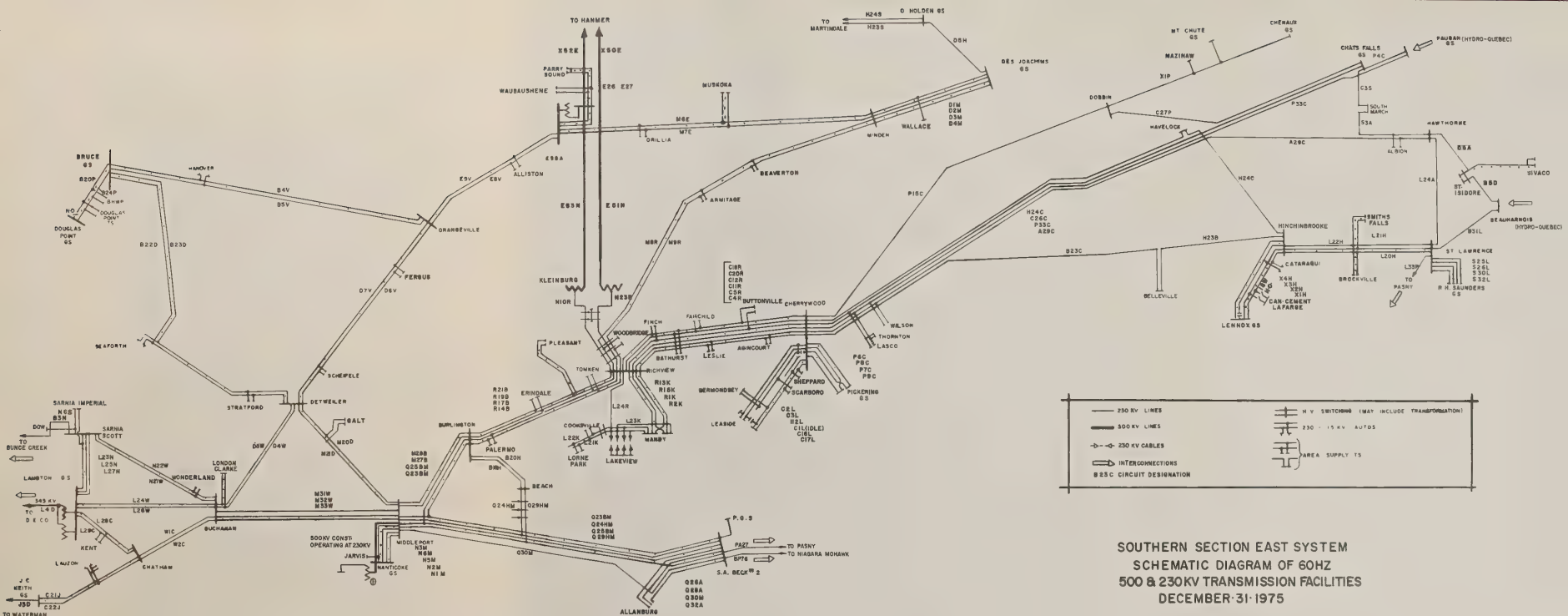
Some users experience reliability better than and some
worse than the average for the whole power supply
system. However, the following examples may serve to
place in perspective the existing reliability of
electric power supply systems:

- The low voltage (13, 28 or 44 kV) buses of step-
  down transformer stations and large industrial
  customers supplied at 115 kV or 230 kV by Ontario
  Hydro experienced interruptions totalling 22
  minutes on the average in 1974 (1). Reliability
  on average was thus 99.9958%. This reflects the
  performance of the generation and bulk power
  transmission systems.

- Data have been accumulated for rural customers in
  nine Ontario Hydro Areas, covering periods from 18
  to 55 months ending December 31, 1974. These
  indicate an average annual duration of
  interruption per customer of 182 minutes (2).
  Reliability on average was 99.9658%. This
  reflects the performance of the generation, bulk
  power transmission, subtransmission and rural
  distribution systems.

- The survey of distribution system performance of
  Canadian utilities conducted annually by the
  Canadial Electrical Association showed an average
  total duration of interruption per customer of 158
  minutes in 1972 and 40 9 minutes in 1973 (3).
  Reliability thus was 99.9699% in 1972 and 99.9222%
  in 1973.

(a) Reliability to the Electric Utility

The electric utility is concerned with planning,
designing, operating and maintaining its power
supply system to provide an acceptable level of
reliability to the users. This requires that
standards of reliability be specified and used in
development of the system and its component parts.

To be used in mathematical calculations,
reliability must be defined as precisely as
possible. According to a standard definition,
reliability is "the probability of a device
performing its purpose adequately for the period
of time intended under the operating conditions
encountered." Probability is a key word in the
definition because probability mathematics is used

to evaluate reliability, and the answers are not
intended to state whether or not a given piece of
equipment will be available at a given time, but
only the probability that it will be available.

Because of the complexity of power systems it is
not practicable to apply this strictly
mathematical definition to overall power system
reliability. Accordingly, power system
reliability is divided into two aspects:
availability which is amenable to probability
analysis, and security which is not.

(i)   Availability

The availability of the individual elements
(generators, transmission lines,
transformers, circuit breakers, etc) of a
power system is the probability that the
individual elements will be in an operable
condition, i.e. not out of service due to a
fault, equipment failure, incorrect operation
or for maintenance.

(ii) Security

System security is a measure of the ability
of the system to withstand the stresses
imposed by sudden shocks, such as loss of
large generators, or a heavily-loaded
transmission line. A transmission system may
have adequate availability, that is, there
may be enough elements to supply the load
under normal steady state conditions. It may
even have adequate availability to supply
steady state loads with one or more elements
out of service. However, if an element is
forced out of service by a fault, there may
be a severe stress placed on the system for a
few seconds because of changes or swings in
power flows occasioned by the fault. The
system has security if it is able to sustain
these power swings and eventually settle down
to an acceptable new steady state. It does
not have security if the power swings
increase in amplitude until instability
results, leading to disconnection of
generators and loss of ability to supply some
of the loads.

System security can be calculated for any particular fault. It is impractical, however, to treat system security on a probability basis for all faults.

(b) Reliability to the User

The user requires electricity only as a means to accomplish some particular purpose at some particular time. Hence, the user's assessment of reliability is probably based not on the degree of continuity of supply but on its complementary aspects; the occasions on which the supply of power is interrupted completely or reduced partly (e.g. by voltage reductions or voluntary or enforced reductions in power use) and the resultant interference with his planned activities.

It is believed that users of electricity are affected by the following aspects of power supply interruptions and reductions:

(i) Their frequency, that is the number of interruptions or reductions per month or per year. Frequent occurrences are more serious than infrequent ones.

(ii) Their duration, that is the length of time they last. Long interruptions or reductions are more serious than short ones.

(iii) Their warning, that is do they begin without notice or are the users forewarned. Interruptions or reductions which occur with no notice or inadequate notice are more serious than ones occurring with adequate notice.

(iv) Their area, that is are they widespread or confined to a small locality. To the community at large widespread occurrences are more serious than local ones.

(v) Their timing, that is do they occur in the day or at night, on working days or weekends, in winter or summer. The effect depends on the user's activities at the time.

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         (vi)   Their cause, that is do they result from
                factors which are capable of being largely
                overcome by the electric supply utility or do
                they result from factors beyond the utility's
                control (e.g. floods, tornadoes, ice storms,
                etc).

10.2.2   Appropriate Level of Reliability

    (a)   Effects of Unreliability

          The full effects of unreliability include not only
          those which each user sees as applying to himself
          in isolation but also the composite effect upon
          the community. For example, widespread and
          frequent outages may affect a manufacturer, not
          only because his own production capability is
          decreased, but also because the interruptions may
          interfere with his sources and costs of materials
          and with markets for his products. As another
          example, a worker in the manufacturing firm may
          suffer more financial loss as a result of
          interruptions in electric supply to that firm, if
          it should result in lay-offs, than as a result of
          interruptions in supply to his residence.

    (b)   Present Practices

          Ontario Hydro and other utilities have evolved
          reliability criteria and practices for the
          planning, design, operation, and maintenance of
          power supply systems by consideration of
          experience, of actual system performance and of
          the cost of improvement in that performance.
          These criteria provide a high and generally
          satisfactory reliability to users. In turn, it is
          believed that the users have progressively adapted
          their production operations and their way of life
          to depend on this level of reliability.

          It has been Ontario Hydro's experience that many
          customers, including large industries, expect a
          high level of reliability and complain if they do
          not receive it. However, the submissions to the
          Ontario Energy Board's 1974 hearings on Ontario
          Hydro's Expansion Program, and to the hearings for
          1975 and 1976 Rates, indicated that various users
          of electricity hold conflicting opinions about
          continuing the present levels of reliability of

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the electric power supply system. Most of the
municipal electric utilities favoured continuance
of present reliability levels, but some
municipalities, some industrial users and certain
special interest groups suggested that the present
levels are too high and should be lowered to
reduce the cost of electric power.

(c)   Theoretical Optimum

In theory, one could plan an economically optimum
power system by balancing the value of increased
reliability to users and the cost of providing
increased reliability in the power supply system.
However, it is not possible to do this for the
following reasons:

(i)   No means exist to compute within reasonable
error the degree of reliability of all the
individual factors affecting a power system
and hence the reliability of supply of power
and energy to a user at a particular point
within the system. Work is proceeding on
methods of doing this. However, the sheer
magnitude of the problem of assessing all
causes and effects of outages on a large
diversified power system such as that of
Ontario Hydro may make it impractical to
calculate the reliability of supply to
specific customers or groups of customers.

(ii) The monetary and non-monetary value of
various degrees of reliability of supply of
power and energy to users is not yet known.
Some benefits of reliability (or costs of
unreliability) to some users are
quantifiable, e.g. production losses and
costs arising from an interruption. Other
benefits are difficult to assess and
quantify, e.g. the value of personal comfort
or safety.

(d)   Studies of Cost of Interruptions to Customers

Utilities in several European countries have
investigated the cost of interruption to various
classes of users and have published the results of
their studies. (References 4,5). The published
material gives considerable detail of the
assumptions and methods used in determining the

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cost of interruptions. It includes examples to
illustrate how this information could be applied;
it does not give cases where the information has
actually been used in making decisions on system
development.

Also in 1972 the Institute of Electrical and
Electronic Engineers conducted a survey of
reliability in 68 industrial plants in the USA and
Canada. (Reference 6). This provided some data on
the cost of interruptions for 41 plants in 9
industries.

(e)   Ontario Hydro Reliability Study

In 1975, Ontario Hydro initiated a program to
study various aspects of system reliability. The
program is directed by a Coordinating Committee on
Reliability, consisting of senior managers.
Organization of the study is shown in Figure 10-2.

The program is intended to provide information on
the value of reliability of electric supply to
customers, and to develop improved methods for
applying this information to planning the power
supply system. It thus represents a step toward
development of the "Theoretical Optimum" level of
reliability as discussed in 10.2.2 (c).

Studies of Customer Viewpoint and Peak and Energy
Load Reduction will be completed in stages through
1976 and 1977; System Reliability will be a
continuing activity.

Progress in the work is indicated by the
following:

(i)   A survey of customers in London was carried
      out to determine the costs and other effects
      of a prolonged interruption which occurred in
      July, 1975. A report of the findings has
      been completed. (Reference 7)

(ii) A survey has been carried out to determine
      the effect of interruptions on "Large Users"
      (i.e. with demand 5000 kW or over) served by
      Ontario Hydro or the municipal electric
      utilities. The survey covered all users in
      this category, a total of about 200. A
      report on the findings is scheduled for 1976.

ONTARIO HYDRO
POWER SYSTEM RELIABILITY STUDY COORDINATION CHART

SECRETARY	STEERING COMMITTEE	EXTERNAL ADVISORY GROUP
	REGIONS SYSTEM OPERATIONS CUSTOMER SERVICE CHIEF ECONOMIST S·T·& D· PUBLIC RELATIONS RESEARCH SYSTEM PLANNING	OMEA, AMEU, AMPCO, CAC, CEMA, SIERRA CLUB, POLL'N PROBE, THUNDER BAY CHAMB. OF COMM. MINISTRIES: IND. AND TOUR., ENERGY, T.E.I.G.A., AGRIC. AND FOOD, ENVIRONMENT

PROJECT COORDINATOR

CUSTOMER VIEWPOINT SUBCOMMITTEE	PEAK AND ENERGY LOAD REDUCTION SUBCOMMITTEE	SYSTEM RELIABILITY
		FULL TIME SECTION SYSTEM PLANNING DIVISION

INITIAL FUNCTIONS:
 	
CUSTOMER CLASSIFICATION
 	
QUALITY OF SUPPLY CLASSIFICATION
 	
SET TERMS OF REFERENCE
 	
CONSIDER USE OF CONSULTANTS
ETC.
	ESTIMATE EFFECTS OF LOAD REDUCTION PRACTICES (I.E. INTERRUPTIBLE CONTRACTS, VOLTAGE AND FREQUENCY REDUCTION AND VOLUNTARY AND CONTROLLED LOAD SHEDDING) ON SYSTEM PEAK AND ENERGY REQUIREMENTS, AND ON CUSTOMERS	STUDIES OF RELIABILITY
		OF 1. GENERATION
		    2. BULK POWER SYSTEM
		    3. SUBTRANSMISSION
		    4. DISTRIBUTION
		    5. INTERCONNECTIONS
		    6. TOTAL SYSTEM
		GOAL: PROBABILITY OF
		       CUSTOMER
		       INTERRUPTION

FIGURE 10.-2

(iii) Similar surveys have been planned to cover
       other customer categories, e.g. Residential,
       Manufacturing, Farm, Commercial, by the end
       of 1977.

(iv)   Work on reliability methods has included
       Ontario Hydro's participation in a project of
       the Northeast Power Coordinating Council to
       develop a method of applying probability
       techniques to the bulk power system,
       including generation and transmission.
       Initial versions of this method will be
       available for testing in 1976 but much
       development work remains to be done. This is
       discussed more fully in Section 10.4.5(b) and
       Appendix 10-0.

(f) Effective Time for Planning Decisions

On a site already owned, and whose physical and
environmental aspects are already known, it now
takes about eight years to construct and bring
into service the first unit at a new thermal
generating station for which all approvals have
been obtained. If a new site must be acquired the
corresponding period is at least twelve to
thirteen years. It takes eight or more years to
establish major new transmission and terminal
facilities for which routes and sites have yet to
be acquired. Thus current planning deals with
facilities coming into service eight or more years
ahead.

Therefore the effect of a change in reliability
criteria may not be felt by the users for eight or
more years. However, if the results are found to
be undesirable, then it may be another eight or
more years before the situation can be corrected.
This long lead-time makes it undesirable to reduce
significantly criteria which have been developed
over many years and on which users have come to
depend.

(g) Future Developments

There will undoubtedly be continued improvement in
the ability to calculate the reliability of the
system, and to make more rigorous calculations of
the probable consequence to users of changes in
reliability criteria. Also, experience with lower

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levels of reliability may be gained as it may not
be possible to maintain present levels.

Calculations and experience, however, will remain
only as a guide to, and not a substitute for,
judgement in the choice of reliability level.
These judgements must in turn be translated into
criteria by which facilities can be planned,
designed and operated.

10.2.3   Requirement for Reserve Facilities

If all system elements were completely reliable, no
reserve facilities would be needed. However, under
actual conditions, the planning of facilities must
recognize and make provision for the following:

(a)   Individual elements in the power supply system
      will become unavailable at times for such reasons
      as:

      (i)   Breakdowns of components because of wear and
             tear, inherent defects, weather conditions
             etc.

      (ii)   Periodic removal from service for preventive
             maintenance to reduce the incidence of
             unexpected breakdowns.

      (iii) Inadequate supplies of critical materials
             such as fuel, heavy water, maintenance
             supplies, etc.

      (iv)   Strikes.

      (v)   "Debugging" problems with new equipment.

Typically a large generating unit may have an
availability in the order of 75%, i.e. the unit
will be capable of being operated about 75% of the
time and 25% of the time it will be defective or
on routine maintenance. Transmission system
components are removed from service by faults from
time to time, and must also be periodically
removed from service for maintenance. In 1974 the
availability of major transmission lines,
including the main terminal equipment, averaged
98.8%. The average circuit is about 40 miles
long.

(b) Projects may fall behind schedule for many reasons, such as construction or purchasing difficulties, technological problems, natural catastrophes, strikes, or delays in obtaining necessary Government approvals. It is unlikely that this can be offset by an advance in schedule for another project.

(c) Actual loads may be higher or lower than the forecast because of changes in economic conditions or new developments in the interval.

(d) The effective capacity of generating units may be less than anticipated due to changes in environmental regulations, shortages of fuel or heavy water, strikes, shortages of maintenance staff, etc.

Users require a level of reliability considerably higher than the availability of individual components in the power supply system such as generators, lines, circuit breakers, transformers, etc. It is therefore necessary to have spare components or capacity so that the system can continue to supply users satisfactorily when some of the individual components are unavailable, and to provide for other contingencies of the type indicated above.

Spare generating capacity is usually designated as reserve generating capacity and for reasons of economy, is operated only when needed. Spare transmission facilities, are normally kept in use. This practice reduces power losses and increases system reliability.

10.2.4   Planning for Reliability

(a)   The General Process

There are differences in the specific processes and concerns involved in planning for reliability in the generating system and in the bulk power transmission system. These will be apparent in the subsequent discussion in Sections 10.3 and 10.4. However, despite these differences in detail, planning for reliability in each system involves:

-    Similar basic concerns

-   Close coordination of planning, design, operation and maintenance

-   Uncertainty of future conditions

These similarities are described further below.

i) Similar basic concerns

    These are:

    -   Capability of equipment and structures, which is related to the inherent mechanical, electrical and structural reliability of the components in the various elements of the system. It reflects the decisions made in design, manufacture and construction and the capability of the equipment and material to perform the duty actually imposed on them. If the duty or the operating conditions are different than assumed in the design their reliability may be affected.

    -   Capability of staff and support services including the availability and competence of the operating staff, the extent of maintenance facilities, the assistance available from consultants and manufacturers for repair and improvement of equipment, etc.

    -   Availability of critical operating and maintenance supplies including such items as fuel, lubricating oil, spare parts, spare transformers, etc.

    -   Unpredictable external factors including strikes, extreme natural phenomenon, (e.g. temperatures, lightning, tornadoes) malicious damage, changes in government regulations, etc

ii) Close Coordination

    Electricity supply systems have grown and are expected to continue to grow by the systematic addition of facilities in relatively small increments. Because of this

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and of the long useful life of the
components, planning for reliability is a
continuing iterative process of consultation
and coordination among those responsible for
planning, designing, manufacturing,
constructing, operating, and maintaining the
facilities.

iii) Underlying of Future Conditions

If reliability is to be satisfactory, the
criteria used in planning must allow for
various adverse possibilities. The load
growth may depart from forecast and if higher
the reliability will be reduced. Projects
may fall behind schedule so that facilities
are not available when planned. Also there
are extreme contingencies which occur
infrequently (e.g. common cause failures,
tornadoes).

(b) Methods of Analysis

As noted in Section 10.2.2(c), techniques are not
available to analyze the reliability of the power
system as a whole. The utility normally analyzes
the energy supply, generation, bulk power
transmission and distribution sectors of the
system individually, dealing only with the most
significant factors in each sector. These factors
are respectively:

- the dependability of primary energy supplies.

- the availability of generating units.

- the security and availability of the bulk
power transmission system.

- the availability of the distribution system.

Present practice is to establish criteria for each
sector, a process which may not ensure the proper
relative level of reliability in each sector.
Ontario Hydro's Reliability Study described in
Section 10.2.2(e) may provide a basis for
establishing proper relative levels.

1	(c) Administrative Factors
2	
3	Some potential causes of unreliability can be
4	recognized in the planning process but are not
5	susceptible to engineering solutions. Instead
6	they require administrative or managerial action.
7	These include fuel supply, which has been
8	discussed in an earlier memorandum (Reference 8),
9	and strikes. They will receive only passing
10	discussion in subsequent sections of this
11	memorandum.
12	
13	10.3 PLANNING FOR RELIABILITY IN THE GENERATING SYSTEM
14	
15	10.3.1 Introduction
16	
17	In planning a reliable generation supply to the
18	electric load the two primary factors are the load
19	forecast with its inherent uncertainty, and the
20	reliability of the electrical generating system. The
21	uncertainty in load forecasts is discussed in the
22	memorandum on load forecasting This section discusses
23	the reliability of the generating system, and the
24	interrelation of the load forecast uncertainty and the
25	generating system unreliability.
26	
27	The generating system includes all generating units
28	connected to Ontario Hydro's bulk power transmission
29	system. Since the capacity of the transmission between
30	the East and West Systems, is limited, it is necessary
31	to analyse these systems separately.
32	10.3.2 Composition of Generating System
33	
34	Ontario Hydro operates a mixture of hydraulic, fossil-
35	steam, nuclear-steam and combustion turbine generating
36	units in widely distributed generating stations. The
37	composition will change with future development.
38	
39	a) Existing Generating Resources
40	
41	Generating resources on the Ontario Hydro system
42	in January 1976 is shown in Appendix 10-A. In
43	summary this was as follows:
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		East System		West System	
		In MW	In %	In MW	In %
Hydraulic		5574	30	576	64
Thermal	Nuclear	2284	13		
	Fossil-Steam	8816	48	97	10.7
	Combustion Turbine	388	2	29	3.2
Purchases		1196	7	200	22.1
	Total	18258	100	902	100

January Dependable
Peak Resources

Appendix 10-A also indicates the energy limitations of
the hydraulic generation. For the East System the
dependable energy available from the existing hydraulic
capacity in January is 2677 average MW i.e., 48% of the
peak dependable capacity. For the West System, the
corresponding figures are 325 average MW and 56.5%.

The hydraulic capacity consists of a large number of
units ranging in size up to 125 MW. In January 1976
the largest nuclear-steam or fossil-steam unit size was
about 500 MW.

b) Trends in Generating Capacity

Most of the hydraulic power potential in Ontario
within economic reach of Ontario load centres has
been developed. Location, cost and environmental
concerns make it doubtful that much of the
remaining potential will be developed; in any case
this could provide only a fraction of the forecast
requirements for future capacity. The trend to
thermal generation in large multi-unit plants,
already established by construction of Hearn,
Lakeview, Lambton, Nanticoke, Pickering and
Lennox, is expected to continue:

i) Up to 1990 most additions to the East System
will consist of either fossil-steam units in

the 500-750 MW range or Candu nuclear units
of 500 MW or 850 MW capacity installed in
four-unit plants.

ii) Up to 1990 additions to the West System will
consist of fossil-steam units in the 200-300
MW range, provided the capacity of the
interconnection between the East and West
Systems is not substantially increased.

Thus, the reliability characteristics of large
thermal generating units are the predominant
factor in planning for reliability in the future
generating system.

10.3.3   Generating System Characteristics

Generating units and their components have already been
described in earlier memoranda. Certain features of
particular significance to reliability of the unit
itself or to the system are described in the
following:

a)   Generating Equipment

i) Thermal steam generating units comprise a
large and complex arrangement of main and
auxiliary equipment which must operate
properly and continuously if the unit is to
provide full output. The units are subject
to deratings or total outage from failure in
any of these many elements; extensive regular
maintenance is necessary to keep down the
number of forced outages.

Also, at fossil-steam plants, large volumes
of fuel must be transferred from storage to
the boilers, e.g. a 500 MW unit burns about
180 tons of coal per hour at full capacity.
Breakdowns in the handling equipment, or such
conditions as wet or frozen coal may force
temporary reductions in output, sometimes for
several units in the same plant.

In addition large thermal units have definite
operating limitations which must be
recognized. These units are restricted in
the rate at which they can vary their output
and require up to thirteen hours to pick up
load from a cold start.

ii) Hydraulic generating units are much simpler
than thermal units. The turbine and
generator are much larger physically in
relation to their capacity.

Forced outages are relatively infrequent and
maintenance requirements are less extensive
than for thermal units.

Hydraulic generating units can be started
quickly and loaded quickly and are thus well
suited for load following and peaking
service.

b) Governors

Each generating unit has a governor which
regulates the flow of energy to the prime mover
e.g. steam to the turbine, so as to maintain
generator output at system frequency, and thus to
match generation to load requirements. Speed of
governor response is important during system
disturbances.

c) Exciters and Voltage Regulators

These control generator voltage to predetermined
levels. Speed of response may be important during
system disturbances.

d) Switching Arrangement

Each generating station has a switchyard to
provide the connecting link between generating
units and the transmission system. This is
arranged so that individual units can be connected
or disconnected without affecting other units, and
so that the switchgear can be maintained without
interfering with the operation of generating units
or transmission lines.

e) Relay and Control Systems

These monitor the operation of the generating unit
and will shut it down automatically or isolate it
from the system for conditions outside
predetermined limits. The primary purpose is to
avoid or minimize damage to the generating unit.
Other uses are to detect and avoid potentially
unsatisfactory operating conditions e.g. excessive

loading, and in minimizing disturbance to the
system for any fault within the unit.

f)   Energy Supply

i) Thermal generating units are dependent on
fuel, supply of which can be disrupted by
mining or transport strikes, weather
conditions, embargoes, etc. The effects of
such disruptions can be partially overcome by
stock piles of fuel at the generating
station, by arranging for use of diverse
fuels, and by arranging alternative sources
of supply for each fuel.

ii) Hydraulic generating units are dependent on
stream flow and the design of the storage
system, and ultimately on precipitation.
This may vary widely from year to year.

10.3.4   Factors Affecting Generating System Reliability

General factors affecting reliability have been
discussed in Section 10.2.3. This section is concerned
with the reliability of generating equipment and
structures.

a)   Security

The security of the generating system is
inherently high because:

i) Generating units are designed to limit the
number of sudden losses of generating
capacity and the design of the bulk power
system is aimed at accommodating those losses
which do occur.

ii) Generating stations are designed to cope with
the sudden stresses which may be imposed on
them by problems on the bulk power
transmission system.

b)   Availability

This is the significant factor in determining
generating system reliability. No generating unit
is completely reliable; each becomes unavailable
for full operation from time to time, because of

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breakdown, the need for maintenance, or for many other reasons such as those listed in Section 10.2.3.

Ontario Hydro keeps detailed records of the performance of its thermal units. They are used as an aid to forecasting future performance of existing and new generating units.

Availability Performance Indices

The specific availability indices used in the generation planning process are:

- The Planned Outage Factor (POF)

    The percent of hours in the year that a unit is scheduled to be out of service for periodic overhaul planned months in advance.

- The Maintenance Outage Factor (MOF)

    The percent of the hours in the year that a unit is scheduled to be out of service (mostly on weekends) for week-to-week repairs.

- Forced Outage Rate (FOR)

    The ratio of forced outage hours (only) to the sum of forced outage hours and operating time.

- Adjusted Forced Outage Rate (AFOR)

    A further expansion of the forced outage rate which includes the effect of forced deratings and the effect of scheduled outage extensions.

- Derating Adjusted Forced Outage Rate (DAFOR)

    An expansion of the forced outage rate which includes the effect of forced deratings, but excludes scheduled outage extensions.

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Definitions of these indices are given in Appendix 10-B.

The definitions used by Ontario Hydro are generally similar to those used by other North American utilities and by the Edison Electric Institute but differ in some details. Broad comparison of indices reported by utilities is possible. However, careful examination is needed to determine all differences in the methods of recording and reporting data before interpretation of the comparison can be made.

Similar availability data are not recorded for Ontario Hydro's hydroelectric units. These units are relatively small and have high availability. Although their capacity is of major significance in supplying the load, their availability characteristics are not significant in determining the reserve requirements of the overall generating system.

Past Availability Experience

Appendix 10-C provides an illustrative sample of the availability data kept for Ontario Hydro's large thermal generating units. This is taken from data for the period 1965-1975 contained in Reference 9.

Forecast Availability

For planning, forecasts are prepared annually of the availability to be expected from existing and new units. For existing units, the estimates include consideration of their experience assessment of their current condition and any planned changes to the units. For new units, the estimates are based on extrapolation from experience with existing units, design data, and, where available, with comparable units or components elsewhere. These latter estimates may change as design proceeds and more detailed information becomes available.

The 1976 Forecast of Outage Indices for Corporate Planning Use are given in Appendix 10-D.

c) <u>Mode of Operation</u>

Generating equipment is designed to operate
primarily in one of four modes, i.e. base load,
intermediate load, peak load or reserve. If it is
operated extensively in a mode other than the one
for which it is designed, or if the operating
conditions (type of fuel, weather phenomena etc.)
are changed, the reliability of the unit may be
affected. Assessment of the mode of operation is
included in estimating future performance factors.

d) <u>Environmental Constraints</u>

These define the conditions which may limit the
discharge of combustion products and rejected heat
from thermal generating stations. The stations
are designed to operate within these constraints
for all normally experienced conditions. Under
adverse local conditions however, e.g. a
temperature inversion, it may be necessary to use
a different fuel or to reduce the loading of
generation at a particular station.

e) <u>Other Factors</u>

There are many other factors which may affect
generating system reliability but which are not
amenable to engineering solutions, e.g. strikes of
operating staff, or major shortages of fuel
because of strikes, embargoes or general
shortages.

f) <u>Availability of Capacity</u>

A proportion of the generating capacity may be
unavailable at any time. To continue to supply
the load under such conditions, it is necessary to
have reserve generating capacity available.
Appendix 10-E shows a histogram of thermal unit
outages from 1970 to 1975. The following
tabulation indicates the approximate range and
average value of unavailable thermal capacity
expressed as a percent of the annual primary peak
load for the years 1970 to 1975:

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Year	Range of Outage %	Average %
1970	0-28	11
1971	1-29	16
1972	3-36	17
1973	3-39	21
1974	5-47	22
1975	6-49	24

g) **Reliability and Maintainability in Design, Construction and Operation of Generating Units**

To improve the reliability of the generating system, two courses of action are open to the utility; one is to provide increased redundancy in the form of additional reserve capacity and the other is to improve the performance of the individual generating units. Most utilities follow both courses of action.

It is Ontario Hydro's policy to design into power stations reliability and maintainability (R&M) equivalent to that of the best similar stations on the North American continent. The objective is to minimize the total life cycle cost of new plants, not just their capital cost.

In 1970, Ontario Hydro formally established a reliability group in its Generation Projects Division. This group was assigned the responsibility for planning and introducing a reliability and maintainability (R&M) program into the design of all future generating stations. The program applies equally to fossil and nuclear stations. The following are the main tasks identified by the program:

(i) Establishment of an R&M program, plans and organization to implement and control the program.

(ii) Introduction of R&M methods in design.

(iii) Collection, analysis and utilization of operational experience data.

(iv) Reliability of equipment: specifications, evaluation and improvement.

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1	(v) Training of engineering personnel in
2	reliability engineering.
3	
4	A further description of this is provided in
5	Reference 10.
6	
7	For existing generating units, a performance
8	review is carried out each year to assess each
9	station and to identify areas where improvement
10	may be possible.
11	
12	10.3.5 Availability Assessment

10.3.5   Availability Assessment

The factors affecting generating system availability can be placed in two categories:

(a) Those whose occurrence can be estimated to a reasonable degree of confidence.

These include:

i) Forced outages and derating of individual units; these are random occurrences which require the unit to be taken out of service or derated as soon as possible.

ii) Maintenance outages and deratings of individual units; these are random occurrences but the outage or derating can be postponed for several days time when it is less likely to interfere with the system's ability to supply the load fully.

iii) Planned outages; these are scheduled to carry out periodic overhauls, generally several months in advance.

iv) Variations in the output of generating units due to known government regulations, normal seasonal changes in temperature, normal river flow variations.

In assessing the availability of the generating system one must recognize that the system must be capable of continuously supplying a load that varies from hour to hour, day to day and from season to season. Figure 10-3 shows the hourly variation for a typical week in December and July. Figures 10-4 and 10-5 show the load and capacity conditions at the time of peak load for
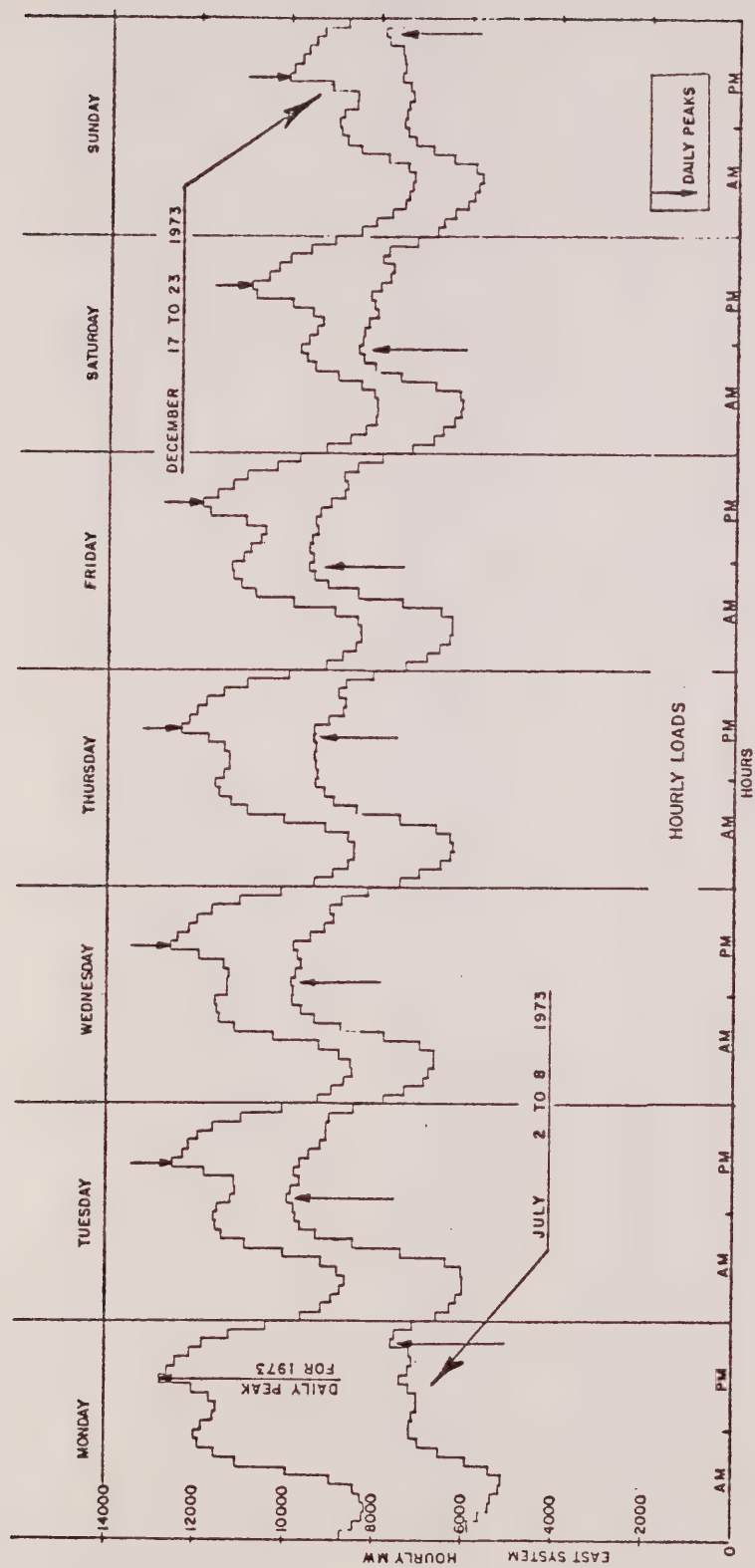
HOURLY LOADS FOR A DECEMBER AND JULY WEEK
ONTARIO HYDRO EAST SYSTEM

FIGURE 10-3

1974 - DAILY PLOT OF EAST SYSTEM CAPACITY AND PRIMARY LOAD, AS A PERCENT OF THE ANNUAL 20-MINUTE PEAK LOAD

A: DEPENDABLE CAPACITY
B: A - PLANNED & MAINTENANCE OUTAGES
C: B - FORCED OUTAGES & DERATINGS
E: DAILY 20-MINUTE PEAK LOAD
F: DAILY MINIMUM LOAD
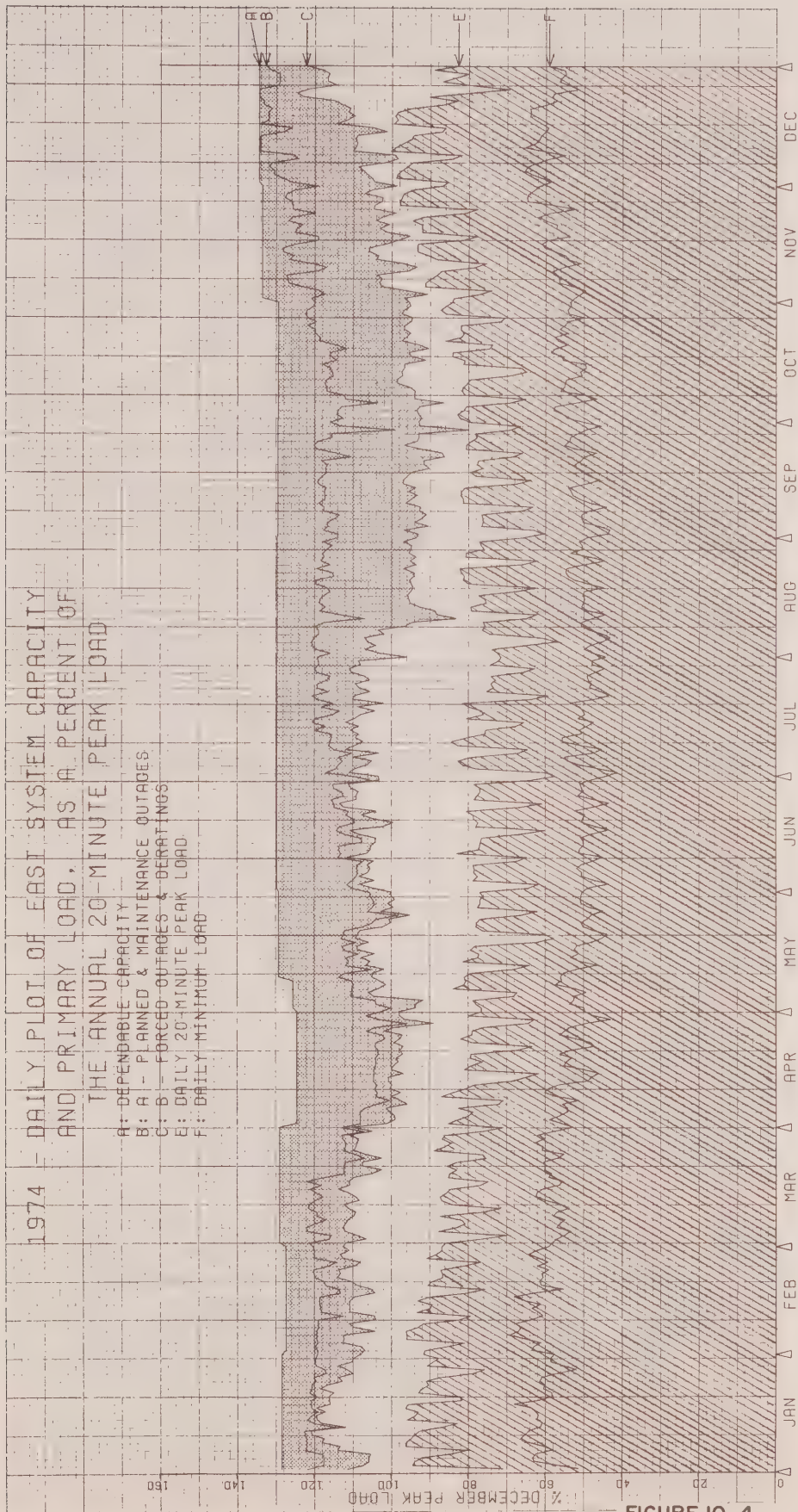
FIGURE 10-4

each day in 1974 and 1975 for the Ontario Hydro East
System.

(b)   Those whose occurrence cannot be estimated with
      any confidence. These include:

      i)   Forced outages or deratings occurring
            coincidentally or overlapping because they
            are interrelated.

      ii)   Variations in output of generating stations
            because of unforeseen government regulations,
            abnormal weather conditions etc.

      iii) Strikes, shortages of critical materials, the
            assistance which can be obtained from
            interconnections and other external factors.

As might be expected, those in category (a) are most
common and have the greatest day-to-day effect. Those
in category (b) occur, but less frequently and with
unpredictable effects. Furthermore, several of them
can be dealt with only by extraordinary action which
must be selected at the time to suit the circumstances.
Accordingly, Ontario Hydro's reliability computations
are principally concerned with factors in category (a).

10.3.6   Computational Techniques

Figure 10-5 shows the relationship between load and
available generation for the East System at the time of
peak load for each day in 1975. The installed reserve
as a percent of the annual primary peak load was 27.1%
and there was only one occasion when the load exceeded
the available dependable generating capacity.

Figures 10-6 and 10-7 show the number of instances when
the firm load would exceed the available capacity
assuming the capacity availability remained the same as
in 1975 but the firm load level is increased such that
the December reserves are 20% and 15% respectively.
Figure 10-8 shows separately the actual reserves for
the above three conditions.

Computational techniques for forecasting reliability
attempt to take into account all the variations shown
in Figures 10-3, 10-4 and 10-5 plus many more, such as
error in forecast loads and generation. They produce a
descriptive index indicative of future system
reliability. Such indices can be interpreted properly

1975 - DAILY PLOT OF EAST SYSTEM CAPACITY
AND PRIMARY LOAD, AS A PERCENT OF
THE ANNUAL 20-MINUTE PEAK LOAD

A: DEPENDABLE CAPACITY
B: A - PLANNED & MAINTENANCE OUTAGES
C: B - FORCED OUTAGES & DERATINGS
E: DAILY 20-MINUTE PEAK LOAD
F: DAILY MINIMUM LOAD

% DECEMBER PEAK LOAD

JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC

FIGURE 10-5

1975 — DAILY PLOT OF EAST SYSTEM CAPACITY
AND PRIMARY LOAD ADJUSTED FOR A 20%
GROSS MARGIN AT THE DECEMBER PEAK

A: DEPENDABLE CAPACITY
B: A + PLANNED & MAINTENANCE OUTAGES
C: B — FORCED OUTAGES & DERATINGS
E: DAILY 20-MINUTE PEAK LOAD
F: DAILY MINIMUM LOAD

FIGURE 10-6

1975 - DAILY PLOT OF EAST SYSTEM CAPACITY
AND PRIMARY LOAD ADJUSTED FOR A 15%
GROSS MARGIN AT THE DECEMBER PEAK

A: DEPENDABLE CAPACITY
B: A - PLANNED & MAINTENANCE OUTAGES
C: B - FORCED OUTAGES & DERATINGS
E: DAILY 20-MINUTE PEAK LOAD
F: DAILY MINIMUM LOAD

FIGURE 10-7

1975 DAILY PLOT OF EAST SYSTEM ACTUAL RESERVES (AFTER FORCED, PLANNED AND MAINTENANCE OUTAGES AND DERATINGS) AS A PERCENT OF THE ANNUAL 20-MINUTE DECEMBER PEAK LOAD

A: ACTUAL 1975 CONDITIONS
B: PRIMARY LOAD ADJUSTED FOR A 20% GROSS MARGIN
C: PRIMARY LOAD ADJUSTED FOR A 15% GROSS MARGIN

% DECEMBER PEAK LOAD

FIGURE 10-8

1   only if one has full knowledge of the computation and
2   the data input.
3
4   (a)   Use of Probability Techniques
5
6   The most commonly used techniques to assess
7   reliability are based on probability methods.
8   These methods recognize that the load to be
9   supplied varies from hour to hour on a daily,
10   weekly and seasonal pattern. The availability of
11   generation also varies in accordance with the
12   combined effects of forced outages and deratings
13   which are random, and planned maintenance,
14   predictable deratings, etc. which are not random.
15   Computational techniques are used to calculate the
16   probability that the available generation will be
17   sufficient to supply the load.
18
19   (b)   Alternative Probability Methods
20
21   Several methods for calculating and expressing the
22   reliability of the generating system have been
23   developed and are described in the literature
24   (Reference 11). The main methods are:
25
26   i)   Loss of Load Probability (LOLP)
27
28   This gives the probability that the available
29   generating capacity will be insufficient to
30   supply all of the daily peak loads. The
31   method considers the peak load on each normal
32   working day of the year, i.e. about 240 days
33   excluding holidays and weekends when the load
34   is low. It also considers forced and
35   scheduled outages and deratings of generating
36   units. Other factors such as load forecast
37   uncertainty, lateness of the in-service dates
38   of new generation and assistance from
39   interconnections can be included in the
40   calculations if adequate information is
41   available. The lower curve on Figure 10-9
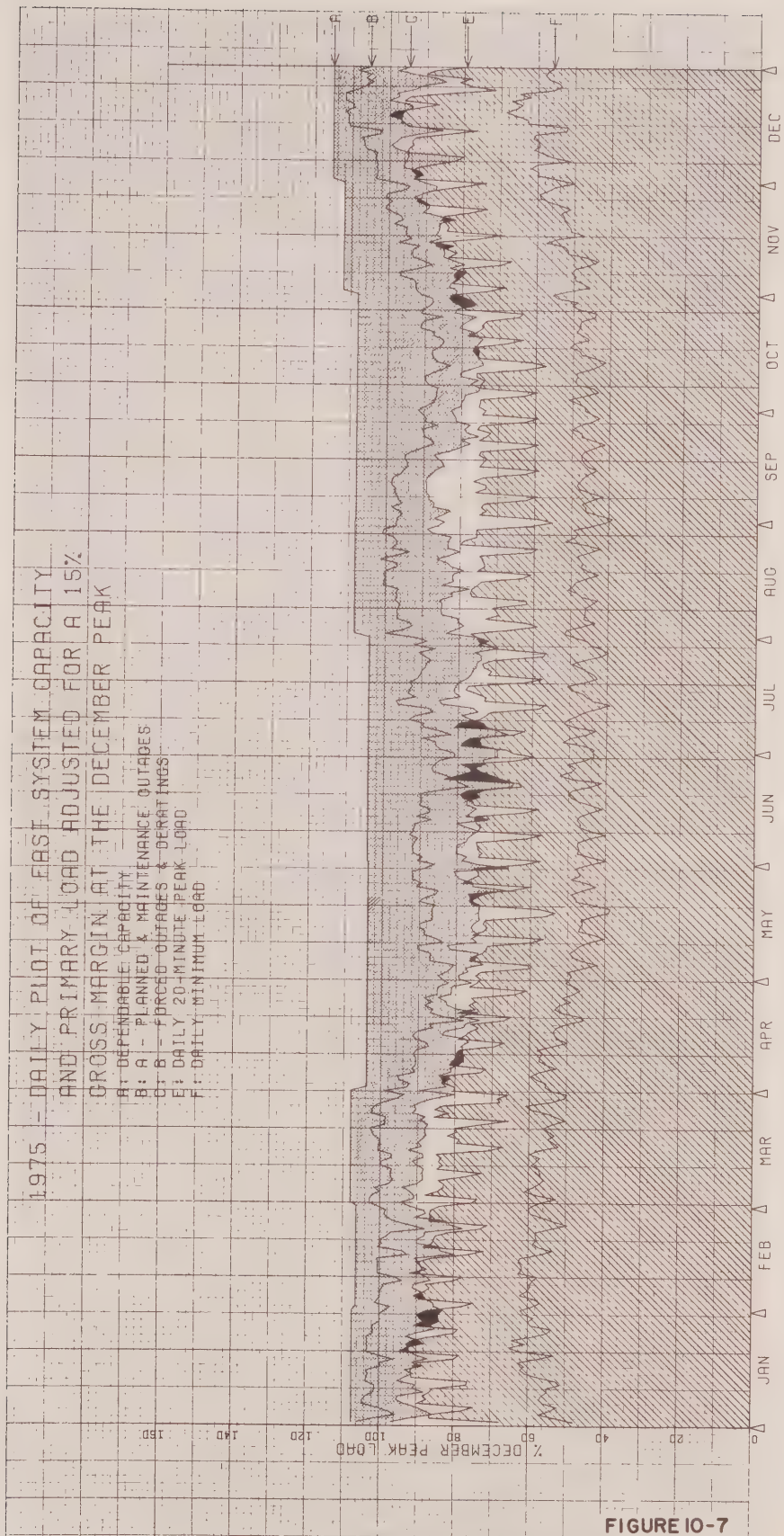42   illustrates the typical variation of the LOLP
43   with installed reserves for the Ontario Hydro
44   East System.
45
46   The result gives no indication of the
47   magnitude or duration of the generation
48   deficiency, only the probability that it will
49   occur, on the average.
50
51
52   10.0 Page 24
53
54
55
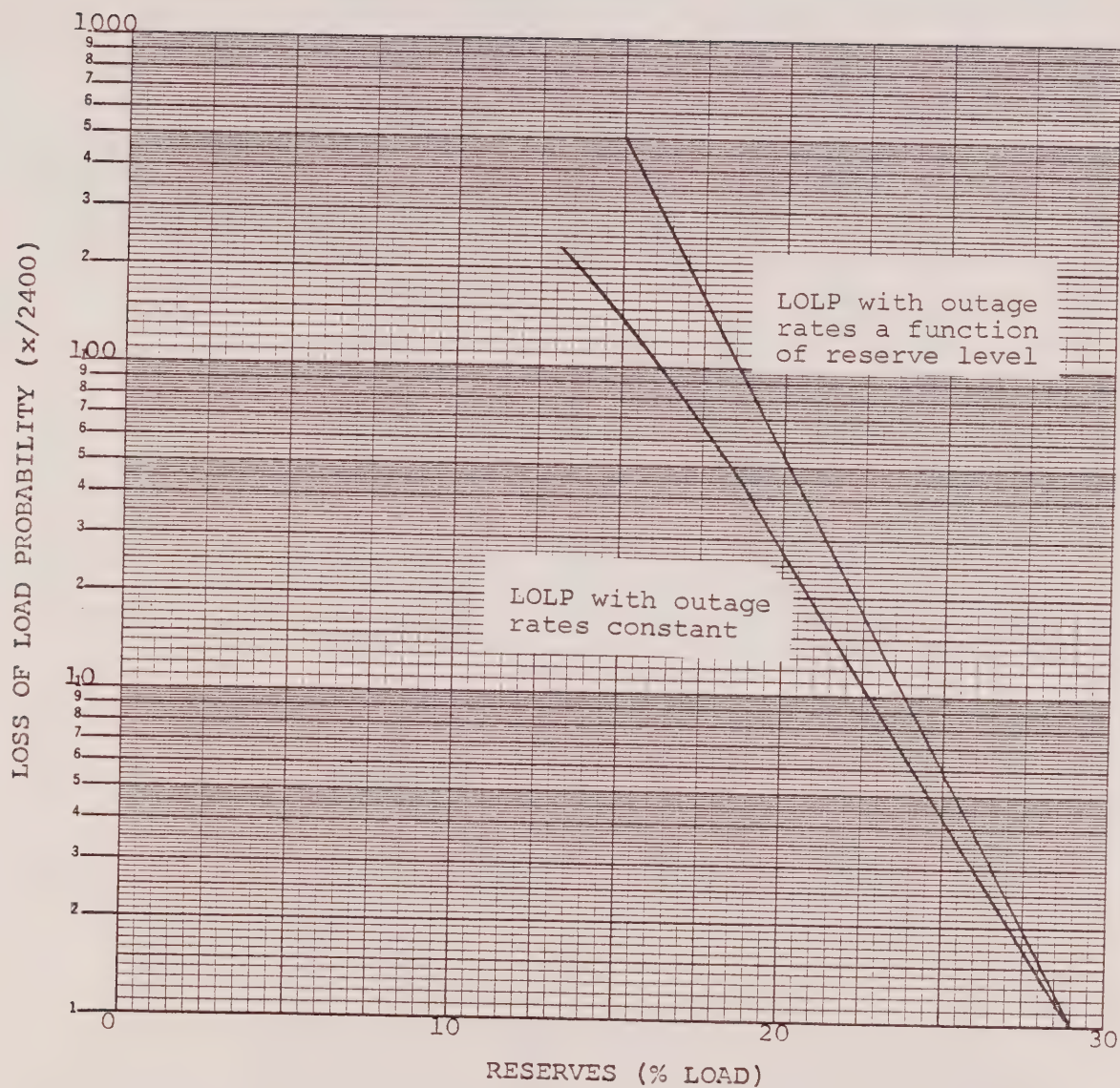
ONTARIO HYDRO EAST SYSTEM
LOSS OF LOAD PROBABILITY VERSUS PERCENT RESERVES

FIGURE 10-9

The seasonal variation of LOLP for various
levels of December installed reserves are
shown in Figure 10-10. For this illustration
it was assumed that no capacity additions
occurred during the year as they normally
would on a growing system. However, normal
seasonal variation of unit output and planned
summer maintenance have been included.

ii) Loss of Energy Probability (LOEP)

This gives the expected average energy which
will be unsupplied, and thus reflects the
frequency, magnitude and duration of the
shortages of capacity. This requires
consideration of the daily load cycle rather
than only the daily peak load. Figure 10-11
illustrates the typical variation of LOEP
with the annual installed reserves.

iii) Frequency and Duration (F & D)

This gives the average number of times and
the average length of time during which
available generation is inadequate to supply
the load. It requires consideration of the
daily load cycle and frequency and duration
of generating unit outages. Figure 10-12
illustrates the typical variation of
frequency and duration of interruption with
different reserve levels for July and
December.

There are differences among utilities in the
methods of application and the definition and
sources of the data used in the above
calculations.

c) Significance of Criteria

Since each of these methods is based on a limited
mathematical representation of the real generation
system, they do not provide an absolute measure of
reliability. They provide only numerical indices.
The calculations can be used to compare the
relative reliability of one plan for generating
system development with another; they can be used
to determine if the indices for a proposed plan
meet specified criteria. Successive adjustments
can be made in a plan and the calculations

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MONTHLY LOSS OF LOAD PROBABILITY
ONTARIO HYDRO EAST SYSTEM

LOSS OF LOAD PROBABILITY (X IN 2400)

DECEMBER INSTALLED RESERVE % LOAD

25%

27.5%

30%

NOTE: i) FOR ILLUSTRATIVE PURPOSES THE INSTALLED CAPACITY
          WAS HELD CONSTANT THROUGHOUT THE YEAR HOWEVER
          NORMAL SEASONAL VARIATION IN OUTPUT
          RESULTING FROM CHANGING HYDRAULIC CONDITIONS
          AND PLANNED OUTAGES HAS BEEN INCLUDED

        ii) THE CAPACITY WAS HELD CONSTANT AND THE LOAD
          VARIED TO YIELD THE INDICATED RESERVE LEVELS

JAN   FEB   MAR   APR   MAY   JUN   JUL   AUG   SEP   OCT   NOV   DEC

FIGURE 10-10

ILLUSTRATION OF THE
VARIATION OF LOSS OF ENERGY PROBABILITY (LOEP)
WITH ANNUAL INSTALLED RESERVES
ONTARIO HYDRO EAST SYSTEM

Installed Reserve % Load	D E C E M B E R			A N N U A L		
	Expected Unsupplied Energy (MWh)	Total Load (GWh)	LOEP % of Total Load	Expected Unsupplied Energy (MWh)	Total Load (GWh)	LOEP % of Total Load
25	233	11,074	.0021	3847	116,522	.0033
27.5	91	10,857	.0008	1699	114,231	.0015
30	36	10,648	.0003	754	112,035	.0007

NOTE:

(a) For illustration purposes, the installed capacity was held constant
     throughout the year; however, normal seasonal variation in output
     resulting from changing hydraulic conditions and planned outages
     have been included.

(b) The capacity was held constant and the load varied to yield the
     indicated reserve levels.
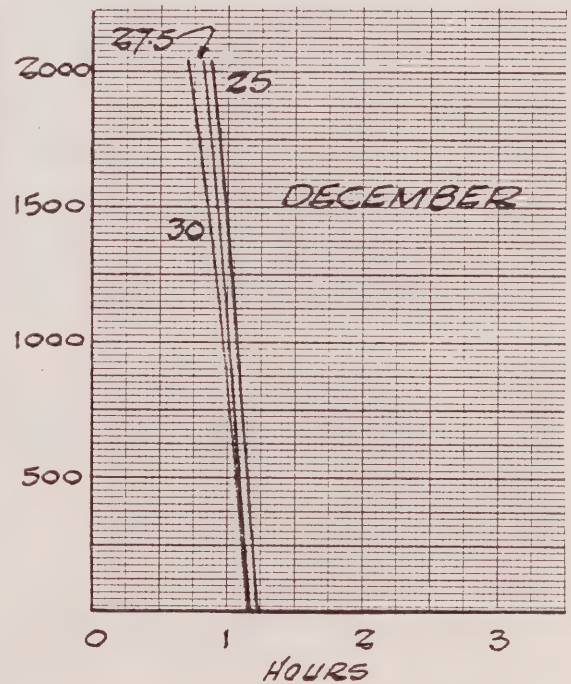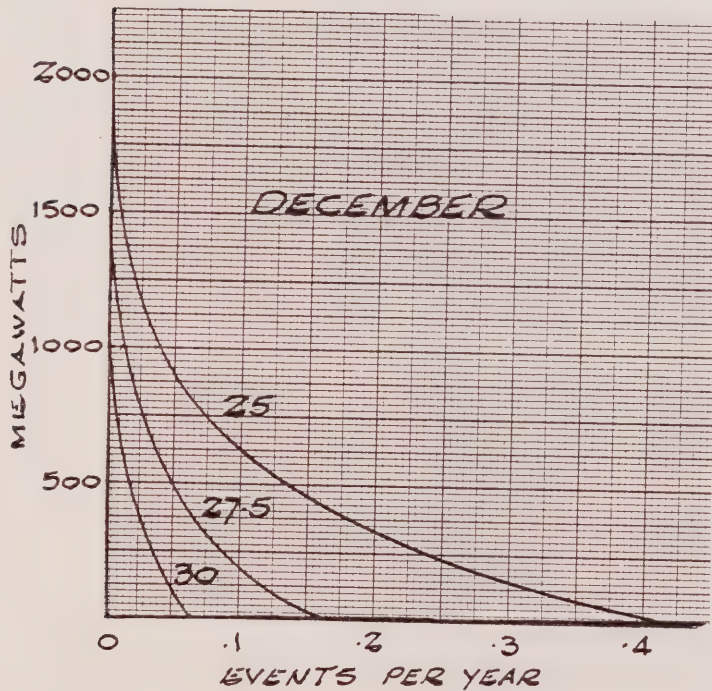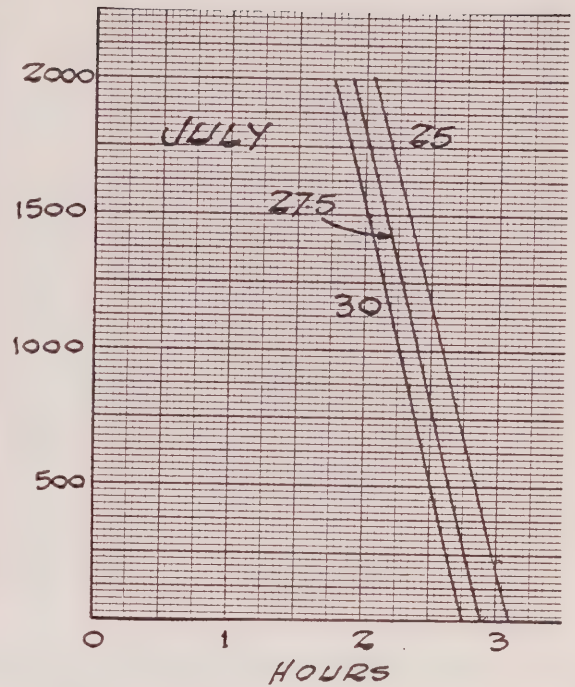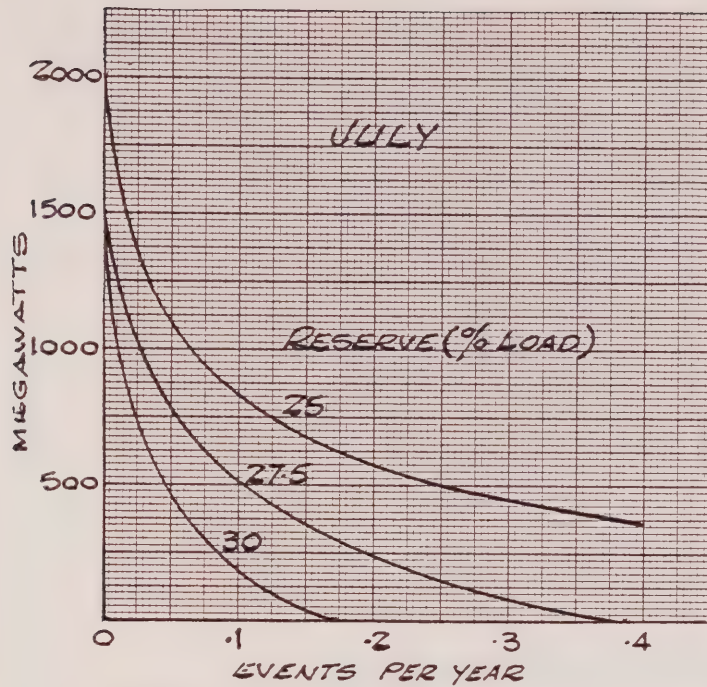
FIGURE 10-11

AVERAGE FREQUENCY OF OCCURRENCE OF ALL EVENTS RESULTING IN LOAD INTERRUPTIONS EXCEEDING THE AMOUNT SHOWN

AVERAGE DURATION OF OCCURRENCE OF ALL EVENTS RESULTING IN LOAD INTERRUPTIONS EXCEEDING THE AMOUNT SHOWN

FIGURE 10-12

1 repeated until the plan meets the specified
2 criteria.
3
4 Furthermore, the indices calculated for long-term
5 planning will almost certainly be different from
6 similar indices calculated for the actual system
7 even if the system is built exactly as planned.
8 This is because, by the time the system is built,
9 actual data will be different from the factors
10 assumed during the planning stage, e.g. government
11 regulations which changed in the interval will be
12 known, the actual rating and performance of new
13 units and the actual loads will be known, and may
14 be different than assumed, etc. It is highly
15 improbable that these data will be as assumed in
16 the planning stage eight to thirteen years
17 earlier, or that the variations in actual data
18 from the planning assumptions will offset each
19 other.
20
21 The value of the computational techniques and the
22 resulting indices is that they permit a part of
23 the problem of assessing reliability which
24 involves a large amount of data to be reduced to
25 simple numerical statements.
26
27 (d) Methods Used by Ontario Hydro
28
29 Several studies of the relative merits of these
30 alternative methods have been reported in the
31 technical literature. These generally conclude
32 that all methods result in similar requirements
33 for future generation, provided:
34
35 i)   the standard or design criteria used when
36   applying each method is selected so as to
37   produce the same actual reserve generating
38   capacity in the initial year of the expansion
39   program,
40
41 ii) there are no basic changes in the hourly load
42   patterns
43
44 iii) There are no major differences in the energy-
45   producing capabilities of the future
46   generation additions.
47
48
49
50
51
52   10.0 Page 26
53
54
55

1	Ontario Hydro has also done some investigation of these
2	methods, but its proposed generation programs have been
3	based on the use of the Loss-of-Load Probability (LOLP)
4	computation. This computation is similar in principle
5	to, but different in detail, from LOLP computations
6	made by other large utilities in North America. The
7	process is described in Appendix 10-F, which includes
8	lists of events which are accounted for and events
9	which are not accounted for. Many of the latter could
10	theoretically be included in the LOLP computation. For
11	some of these, however, it is difficult or impossible
12	to estimate the probability or ramifications of the
13	event with any reasonable confidence. It is considered
14	preferable to omit them and make the assessment of
15	their effect a clearly identified matter for judgement.

10.3.7   Results of Sample Calculations

After taking account of maintenance and planned
outages, that portion of the remaining capacity which
can be expected to be unavailable at any time will vary
with the value of the Adjusted Forced Outage Rates
(AFOR's) and the sizes of generating units. For given
conditions of AFOR's and unit size, the amount of
reserve capacity required will vary with the level of
reliability desired. The relationship of these factors
is indicated by the the results of calculations
performed using Ontario Hydro's LOLP program and
presented in Figures 10-13 and 10-14.

Some idea of the effect of the various factors may be
gained from the following extracted from Figure 10-14,
for fossil-steam units of the sizes expected to be used
on the East System.

	Unit Size	AFOR's	LOLP	Required Reserve % of Load
i)	Effect of Size			
	500	8	1/2400	12
	750	10	1/2400	19
ii)	Effect of AFOR's			
	500	6	1/2400	8
	500	8	1/2400	12
	500	10	1/2400	16
iii)	Effect of Reliability Level			
	500	8	1/2400	12
	500	8	1/240	10
	500	8	1/24	8

The Required Additional Generating Reserves,
Expressed As a % of the Additional Load That Can Be Supplied
With a Specified Target Reliability, for the
Addition* of a Series of Identical Generating Units

The Additional Load That Can Be Met
With the Specified LOLP Index, in MW
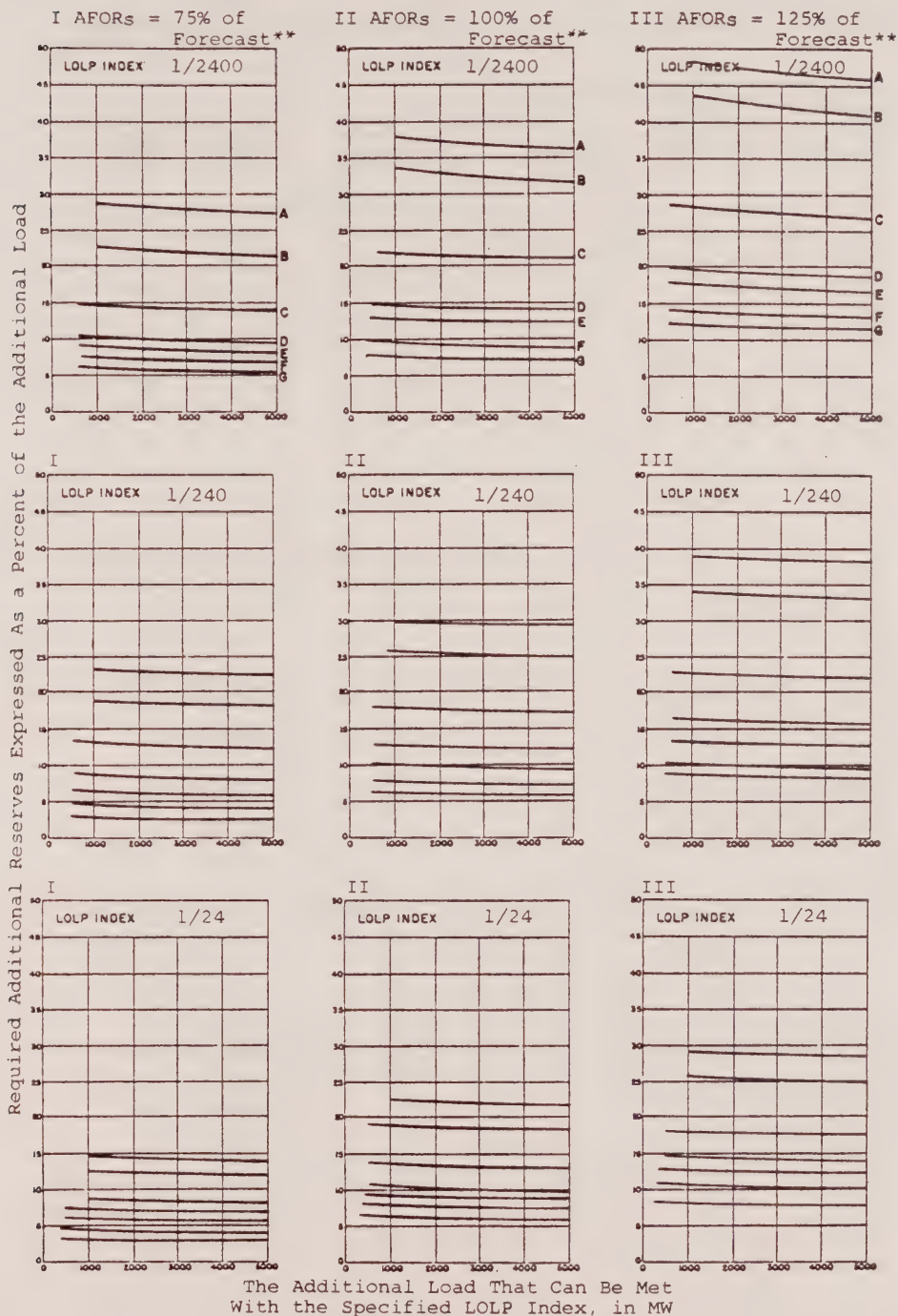
* Additional units added to Ontario Hydro's existing and
  committed system as of January 1976, plus Bruce B GS and
  Darlington GS.

** 1975 forecast of mature AFORs.

FIGURE 10-13

Estimates of the Required Percent Reserve Capacity
Associated With a Major Series of Additions of Identical Units*

Type of Units		Forecast**	Required Reserve As % of Load		
			AFORs 75% of	AFORs 100% of	AFORs 125% of
MW	Type	AFOR, %	Forecast	Forecast	Forecast

I   Loss of Load Probability 1/2400

	MW	Type	AFOR, %	75%	100%	125%
A.	1250	Nuclear	12)	23	32	42
	1200	Fossil	12)			
B.	1000	Fossil	12	20	27	36
C.	850	Nuclear	10)	14	19	25
	750	Fossil	10)			
D.	600	Nuclear	9)	10	14	19
	500	Nuclear	9)			
E.	500	Fossil	8	8	12	16
F.	300	Nuclear	8	6	10	13
G.	200	Nuclear	8	5	7	10

II   Loss of Load Probability 1/240

	MW	Type	AFOR, %	75%	100%	125%
A.	1250	Nuclear	12)	19	26	34
	1200	Fossil	12)			
B.	1000	Fossil	12	16	23	30
C.	850	Nuclear	10)	11	16	21
	750	Fossil	10)			
D.	600	Nuclear	9)	8	12	16
	500	Nuclear	9)			
E.	500	Fossil	8	7	10	14
F.	300	Nuclear	8	5	8	12
G.	200	Nuclear	8	4	7	9

III Loss of Load Probability 1/24

	MW	Type	AFOR, %	75%	100%	125%
A.	1250	Nuclear	12)	13	19	25
	1000	Fossil	12)			
B.	1000	Fossil	12	12	17	23
C.	850	Nuclear	10)	8	13	17
	750	Fossil	10)			
D.	600	Nuclear	9)	6	10	13
	500	Nuclear	9)			
E.	500	Fossil	8	5	8	11
F.	300	Nuclear	8	4	7	10
G.	200	Nuclear	8	4	6	8

* Additions to Ontario Hydro's existing and committed system as
   of January 1976, plus Bruce B GS and Darlington GS. The per-
   centages shown correspond to the amounts by which the addi-
   tions in capacity exceed the additional load that can be sup-
   plied with the shown Loss of Load Probability.

** 1975 forecast of mature AFORs.

FIGURE 10-14

It will be noted that the level of reserve is sensitive to all factors but particularly to the AFOR's; a 25% change in AFOR's produces the same 4% reduction in reserve requirements, as reducing the reliability level by two orders of magnitude, i.e. from 1/2400 to 1/24.

10.3.8 Additional Factors

The factors not included in the LOLP calculations have been referred to in Section 10.3.5. Appendix 10-F lists seventeen factors in all. Of these, twelve would clearly be adverse to reliability if they materialized, three might be adverse or beneficial depending on their particular nature, and two, voltage reductions and assistance from interconnections, would be beneficial. The following is a brief discussion of some of these factors:

(a) Load Reductions Due to Voltage Reductions

Voltage reductions imposed in November 1974 indicated that a 5% reduction in supply voltage would result in a sustained reduction in load of 2.8%. The reduction in load due to voltage reductions during non-winter months is not known.

If Ontario Hydro's reserve margins are substantially reduced for any reason, system voltage reductions will be made more frequently. In this case, it is possible that some customers will install compensatory equipment to reduce the effect of the reductions on their operations. If this type of reaction is widespread, the reduction of 5% in supply voltage will probably result in less than a 2.8% reduction in load during the winter months.

Ontario Hydro considers that voltage reductions should not be used to reduce planned generation reserves but should be held available for use in the event of major contingencies or actual loads being greater than forecast.

(b) Assistance from Interconnections

Following any contingency which suddenly reduces the total output of Ontario Hydro's generation, power flows instantaneously into Ontario from neighbouring systems in the United States and

Manitoba. Provided these power inflows and
conditions in Ontario permit continued stable
operation of the Ontario and the interconnected
systems, the power inflow will effectively replace
the reduction in Ontario Hydro generation.

However, it cannot be assumed that this flow of
power into Ontario will continue automatically for
the period of the contingency. This is because
under the principles of interconnected operation,
Ontario Hydro must increase the output of its own
generation or it must arrange for continued
assistance from the interconnected utilities. If
further contingencies on the Ontario Hydro system
result in a succession of reductions in
generation, a limit will be reached on the power
assistance available from interconnections. This
limit will depend on the operating conditions
existing in Ontario and the neighbouring
utilities, and also on the capability and the
willingness of these utilities to provide
continued increasing assistance.

There is no doubt that interconnections can
provide improvements in reliability or can be used
to enable reductions in installed generating
capacity. This is illustrated in Figures 10-15
and 10-16. However, the improvements or
reductions diminish rapidly if the various
interconnected systems all reduce their level of
reliability. This is considered to be the likely
course of utility development in the period 1980-
1985, and is a serious concern to Ontario Hydro.

It appears that Ontario Hydro's neighbouring
utilities will be tending to reduce their reserve
margins in the period 1980 to 1985. If actual
installed reserves prove to be low in this period,
forced outages will increase because of the
inability to schedule proper maintenance.
Therefore, the reliability of the interconnected
systems will be much lower than the recent levels.
Under these circumstances, it is unlikely that
neighbouring utilities will be able to provide
much assistance to Ontario Hydro or that they will
be prepared to provide such assistance at times
when their own actual generating reserves are
small.
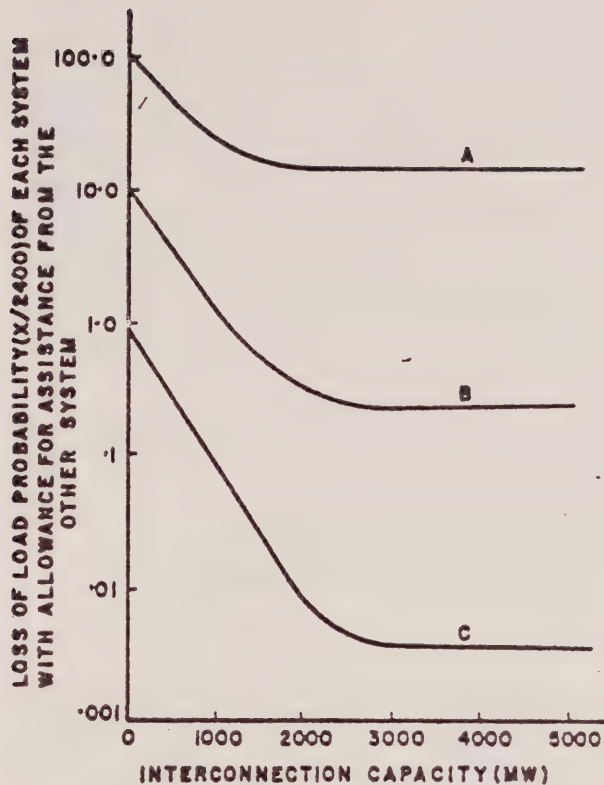
10.0 Page 29

Based on Ontario Hydro East System generation proposed
for December 1982 interconnected with identical system.
Each system's reserve is held constant at the level
which provides the following LOLP with zero inter-
connection capacity.

    Case (a)   100/2400

    Case (b)   10/2400

    Case (c)   1/2400

ILLUSTRATION OF THE IMPROVEMENT IN THE LOSS OF LOAD PROBABILITY AS A FUNCTION OF THE INTERCONNECTION CAPACITY

FIGURE 10-15

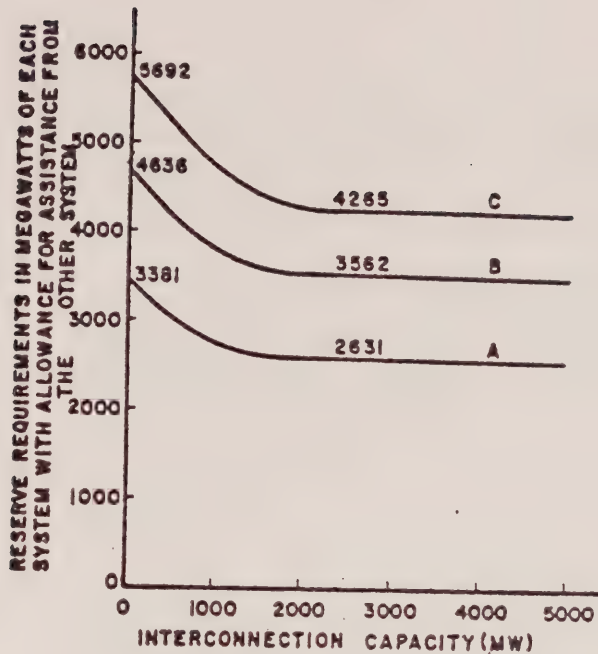Based on Ontario Hydro East System generation proposed
for December 1982 interconnected with identical system.
Each system reduces its reserve after interconnection
to maintain LOLP at the following level:

      Case (a)   100/2400

      Case (b)   10/2400

      Case (c)   1/2400

ILLUSTRATION OF THE POSSIBLE REDUCTION IN RESERVE
REQUIREMENTS AS A FUNCTION OF THE INTERCONNECTION
CAPACITY

FIGURE 10-16

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The reliance upon interconnections with the United
States for reducing planned generation reserves is
a questionable practice, in view of the ability of
regulatory agencies to prohibit or control
extended power flows between the two countries.

For these reasons, Ontario Hydro does not use
interconnections to reduce planned generation
reserves, but holds them available for improving
reliability in the event of major contingencies or
actual loads being greater than forecast.

c)   Relation of Forced Outage Rate to
     Reserve Level

The normal LOLP computation is based on adjusted
forced outage rates derived from operating
experience with systems having reserve levels
which are reasonably adequate to permit normal
maintenance outages. For lower reserve levels
restrictions on outages for maintenance are
certain to reflect in higher forced outage rates -
i.e., the forced outage rate becomes a function of
the reserve level. This in turn would increase
the LOLP probability.

Statistical information is not available to use in
such a computation. An approximation of the
effect on the LOLP-Reserve function is shown in
Figure 10-9, as derived in Reference 12. Also
shown on this Figure is the relationship between
LOLP and reserve if forced outage rates are held
constant at the forecast value.

d)   Load Forecast Error

An analysis of Ontario Hydro's record indicates
that its load forecasts are, in a relative sense,
quite accurate. One-year forecasts have about two
chances in three of being in error by +3% or less.

However the period of forecast that is of concern
in planning the percentage installed reserve
capacity is much greater than one year. For most
of the generating stations being installed, the
minimum period of forecast that will permit
deferment of in-service dates without extreme
disruption and increase in cost is six years. On
the other hand, the minimum notice for

1 installation of a unit is eight years. For a six-
2 year forecast there is about a one in three chance
3 of it being in error by ±7.5% or more.

5 e) Latefall of Unit In-Service Date

7 There are numerous and changing reasons for actual
8 commercial in-service dates being different from
9 those scheduled at time of commitment. Unlike the
10 load forecast error, there is a built-in bias for
11 latefall in the case of in-service date forecast
12 error, deriving from the strong cost incentive for
13 "tight" schedules, i.e., there is a greater
14 probability of a unit being late than early.

16 Figure 10-17 shows a probability distribution of
17 the variation of in-service dates from the
18 forecast dates at time of commitment. The data
19 base is Ontario Hydro's thermal units installed
20 during the past 25 years. From the data, it can
21 be shown that the most probable schedule deviation
22 is 24 weeks latefall, and that there is about a
23 one chance in six of a 64-week latefall or greater
24 and the same chance of a 4-week or greater
25 advancement.

27 A wide variety of factors contribute to the
28 statistics on which Figure 10-17 is based, some of
29 which may not apply to future installations.
30 However, the data illustrate the probability of
31 error in forecast capacity due to variations of
32 actual in-service dates from the planned dates.

33 f) Combined Effects of c), d), and e)

35 The data on probability of error in forecast load
36 and capacity has been combined and the effect on
37 reserve is shown in Figure 10-18 for a six-year
38 forecast with the system load growing at the
39 historical rate of 7% per annum. It may be noted
40 that for a target reserve of 24%, if only load
41 forecast error is considered, there is one chance
42 in three that the reserve will fall outside the
43 range of 15 to 35%. If the forecast capacity
44 error is included the corresponding range becomes
45 11 to 29%.

47 Combining the error in forecast reserve with the
48 approximated LOLP-Reserve function shown in Figure
49 10-9 gives LOLP in terms of target reserve as
50 shown in Figure 10-19 and in terms of target value
51 of LOLP as shown in Figure 10-20. These figures
52 illustrate the dramatic increase in LOLP as target
53 reserve is lowered.

PROBABILITY OF IN-SERVICE DATE DELAY
(BASED ON HISTORY OF 32 ONT. HYDRO UNITS)

NUMBER OF UNITS HAVING A DELAY EQUAL TO OR GREATER THAN SHOWN

PROBABILITY OF DELAY BEING EQUAL TO OR GREATER THAN SHOWN

DELAY OF IN-SERVICE DATE (WEEKS)

FIGURE 10-1

RANGE OF RESULTANT RESERVE
AFTER A 6 YEAR FORECAST
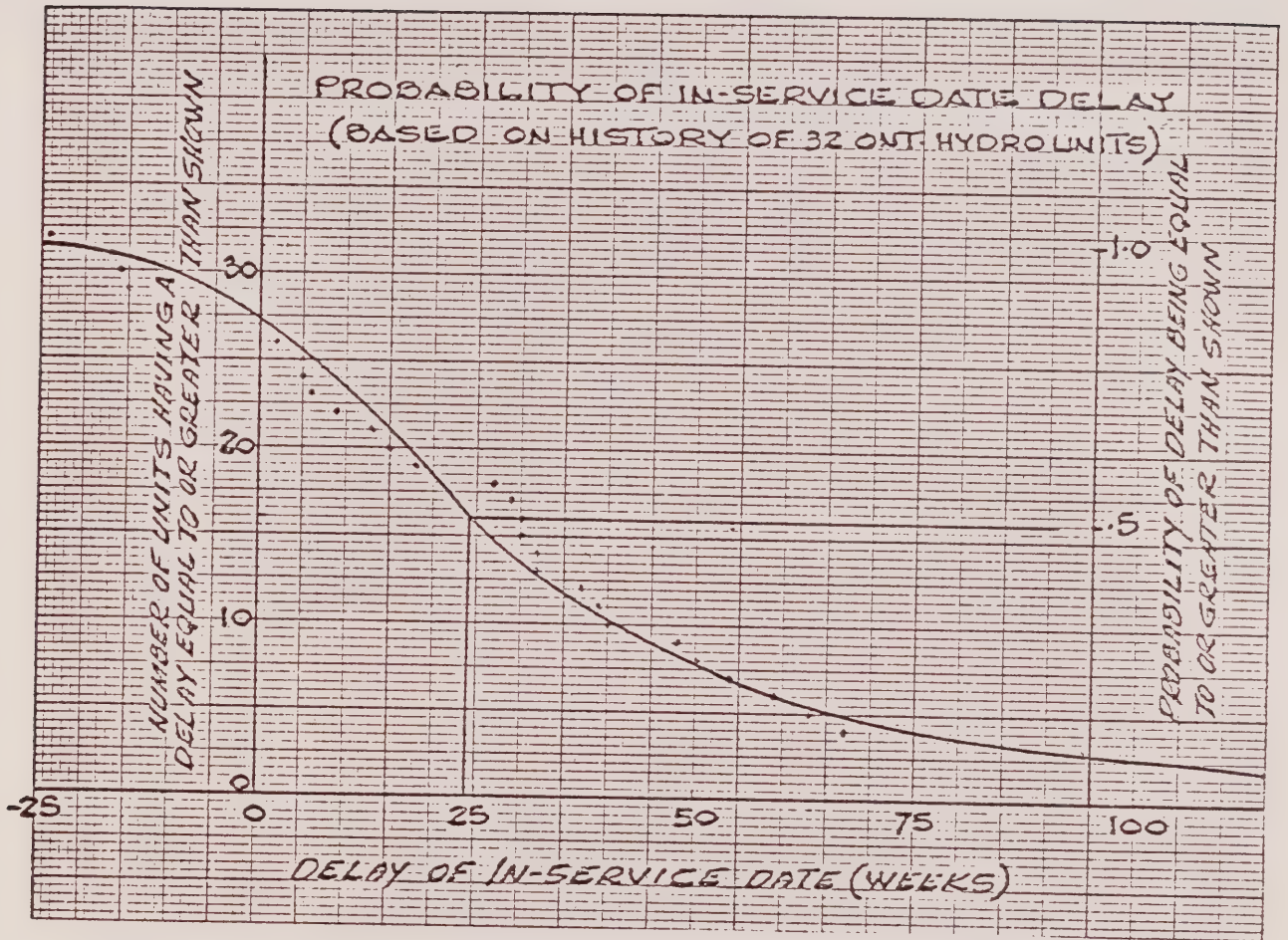
RESULTANT RESERVE (% FIRM LOAD)

FORECAST RESERVE (% FIRM LOAD)

1:3 PROBABILITY THAT RESERVE
WILL BE OUTSIDE BOUNDS
(i) CONSIDERING ONLY LOAD ERROR
(ii) CONSIDERING BOTH LOAD
AND IN-SERVICE DATE
ERROR

(a)

RANGE IN ERROR OF RESULTANT
RESERVE AFTER A 6 YEAR FORECAST

ERROR IN RESULTANT RESERVE
AS A PERCENT OF (FORECAST) RESERVE

PLANNED RESERVE
(% FIRM LOAD)

1:3 PROBABILITY THAT ERROR WILL
BE GREATER THAN SHOWN
(i) CONSIDERING ONLY LOAD ERROR
(ii) CONSIDERING BOTH LOAD AND
IN SERVICE DATE ERROR

(b)

FIGURE 10-18

ONTARIO HYDRO EAST SYSTEM
FORECAST RESERVES VERSUS RESULTANT
LOSS OF LOAD PROBABILITY
FOR A 6 YEAR FORECAST

1:6 PROBABILITY THAT
RESULTANT LOLP WILL
BE LOWER THAN THIS LEVEL

1:6 PROBABILITY THAT RESULTANT
LOLP WILL BE HIGHER THAN
THIS LEVEL

1:2 PROBABILITY THAT RESULTANT
LOLP WILL BE HIGHER
THAN THIS LEVEL

RESULTANT LOSS OF LOAD PROBABILITY (×/21·00)

2000

1500

1000

500

0   10   20   30   40

FORECAST RESERVES (% FIRM LOAD)
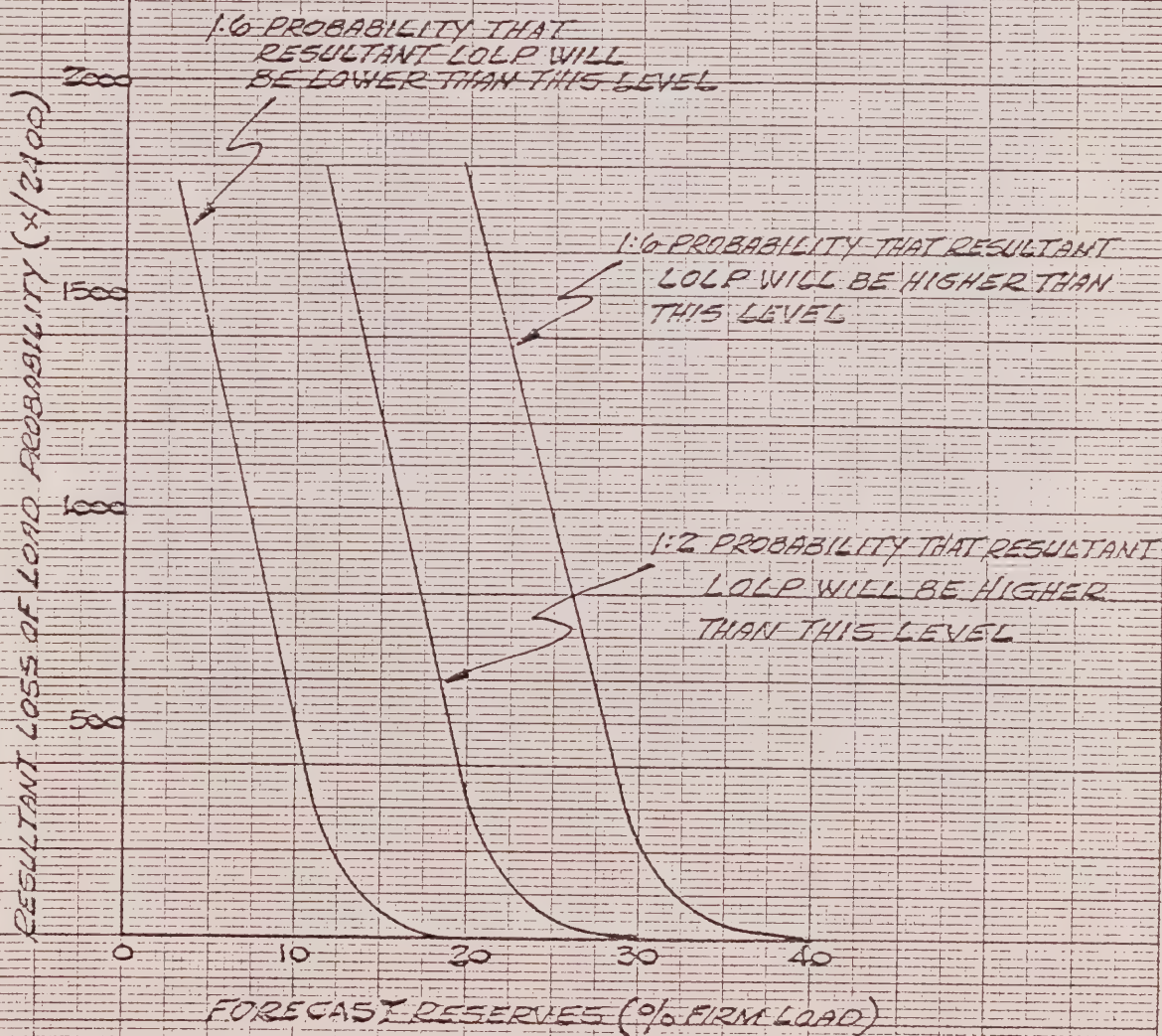
FIGURE 10-19

ONTARIO HYDRO EAST SYSTEM
RESULTANT LOLP FOR A
6 YEAR FORECAST
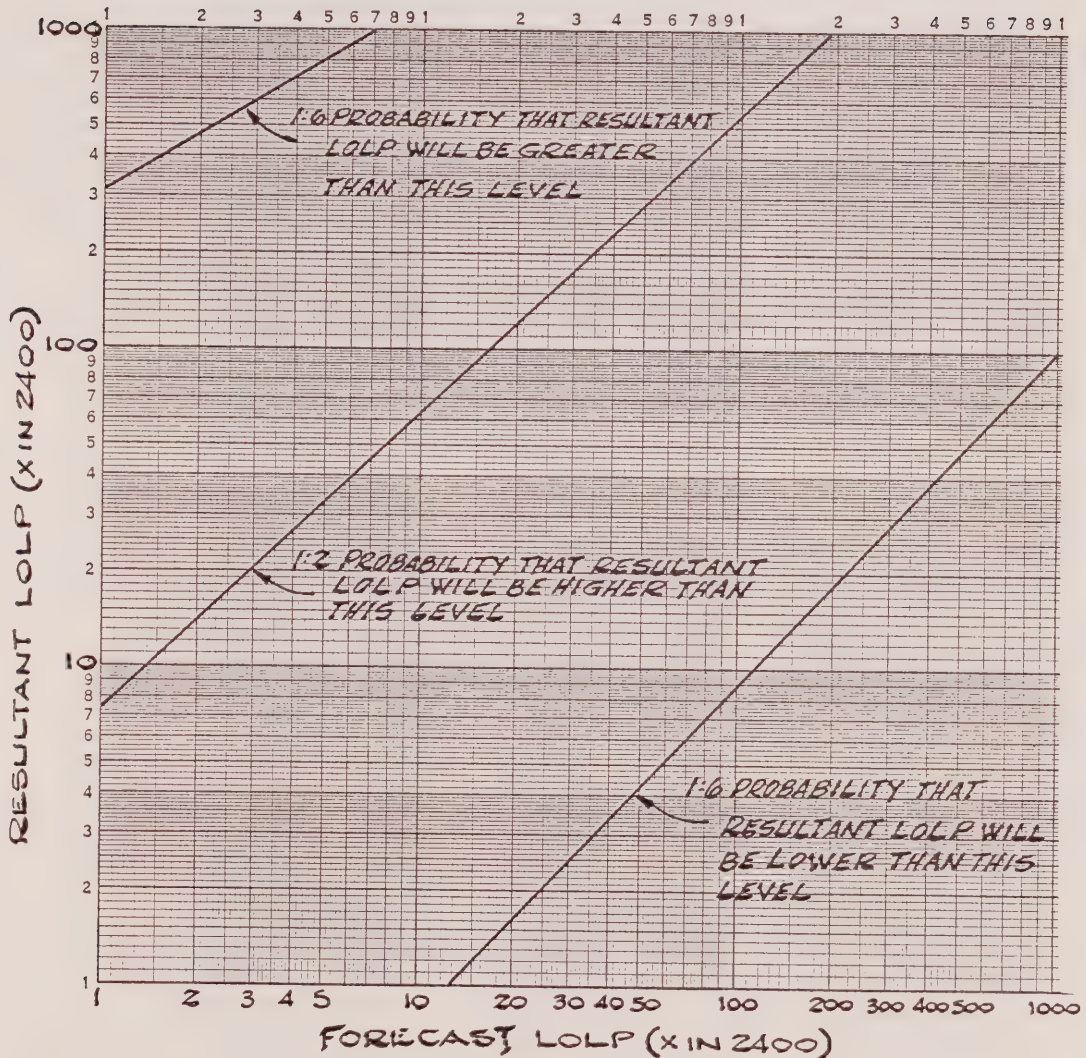
FIGURE 10-20

1	For example, if target reserve is 29% to give a
2	target LOLP of 1/2,400, there is one chance in two
3	that the resultant LOLP will exceed 7/2,400, and
4	one chance in six that it will exceed 300/2,400.
5	However, if target reserve is reduced to 24% to
6	give a target LOLP of 10/2,400, there is one
7	chance in two that the resultant LOLP will exceed
8	60/2,400, and one chance in six that it will
9	exceed 1,300/2,400.

(g) Load Reductions by Controlled
Frequency Reductions

Isolated systems may rely on reducing frequency to
reduce load in emergencies. Ontario Hydro
however, is interconnected with the North American
network and can reduce frequency only if the whole
network does so, or by opening interconnections.
Neither course is desirable. Furthermore, large
modern steam turbines are designed to operate in a
narrow band about the standard frequency; any
significant and sustained departure from this
would have a very adverse effect on the life of
the turbine blades.

(h) Other Factors

Other factors listed in Appendix 10-F but not
included in the LOLP have occurred from time to
time but their probability of occurrence is
difficult to predict accurately. However,
allowance for them must be made in selecting the
level of reserve. This is done by judgement in
the choice of the criterion for LOLP and the
reliance to be placed on interconnections.

10.3.9 Criteria For Generating System Reliability

(a) Effect of Unreliability

Utilities have generally designed their generating
systems to high levels of reliability. The
underlying considerations can be directly related
to the effect on customers in terms of some of the
factors listed in Section 10.2.1(b) Specifically:

i) A shortage of generation is likely to cause
large interruptions i.e. several hundred MW,
as compared to interruptions for other
causes. This is likely to result in load

1   cuts distributed among many customers on a
2   rotating basis. Its effect will therefore be
3   widespread.
4
5   ii) A shortage is likely to prevail over several
6   daily load cycles at least.
7

(b)   NPCC Criteria

Ontario Hydro is a member of the Northeast Power
Coordinating Council (NPCC). The Council is a
group of the major electrical utilities in
Ontario, New York, New England and New Brunswick.
It was established in 1966 as a result of the
massive power failure of November 9, 1965. Its
purpose is to promote maximum reliability and
efficiency of electric service in the
interconnected systems by extending the
coordination of their system planning and
operating procedures.

The Council's "Basic Criteria for Design and
Operation of Interconnected Power Systems", is
attached as Appendix 10-G. This document which
has been adopted by the members of the Council,
states that:

"Generating Capacity will be installed and located
in such a manner that after due allowance for
required maintenance and expected forced outages,
each area's generating supply will equal or exceed
area load at least 99.9615% of the time. This is
equivalent to a loss of load probability of one
day in ten years".

(c)   Ontario Hydro Criterion

Ontario Hydro had adopted the use of the LOLP
method and the 1/2400 (commonly referred to as
"one day in ten years") criterion for planning its
East System before it joined the NPCC. There are
differences in method of computations, input data,
and application of this criterion among NPCC
members. In Ontario, this criterion corresponds
to a generating supply available
99.9585(2399/2400) of the time, not 99.9615%
(2599/2600) and it is applied on a monthly basis.
By this it is meant that to establish installed
reserve requirements Ontario Hydro applies the
criterion that the LOLP for each month should be

10.0 Page 33

1 no greater than 1/2400. This has resulted in
2 reserve requirements being set by December
3 conditions since these result in the lowest
4 reliability.
5
6
7 The inability to calculate a theoretically optimum
8 level of reliability has already been discussed.
9 The choice of the 1/2400 criterion is based on
10 experience and judgement of the level of reserves
11 needed to provide for both the quantifiable and
12 unquantifiable factors listed in Appendix 10F
13 which result in generation loss, without
14 significant risk of failure to supply the load.
15
16 A study of the rationale for this choice has
17 recently been carried out and is contained in
18 Reference 12. The analysis there shows that any
19 reduction below the planning level of 1/2400
20 greatly increases the risk of interruption. The
21 conclusions, in part, are as follows:
22 "
23 LOLP as computed by Ontario Hydro ignores numerous
24 items, some of which have substantial impact upon
25 reliability. Experience has shown that this approach
26 is appropriate provided the criterion for planning
27 reserve is based on a LOLP of approximately 1/2400.
28 However, if target reserve is deliberately lowered to
29 any substantial degree, the computation is inadequate
30 for assessing the reduction in reliability for two
31 principal reasons. The first is that the range of
32 error in the target reserve normally tolerated by the
33 traditional criterion, moves rapidly, as the target
34 reserve is lowered, into a range of the normal LOLP-
35 Available Reserve Relationship in which the increase in
36 LOLP is extremely rapid for small decrements of
37 reserve. The second is that the relationship itself is
38 altered from that prevailing at usual levels of target
39 reserve in such a manner as to severely compound the
40 effect of error in reserve forecasts".
41 "Thus, what may appear to be a modest reduction in
42 target reserve from the traditional criterion can
43 easily present a serious hazard to the system
44 reliability".
45
46 "The results of deliberate reduction in target reserve
47 will not likely become apparent until after an elapsed
48 period of about eight years at which time it will take
49
50
51 10.0 Page 34
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55

1　　　　　　an all-out-effort for the subsequent decade to begin to
2　　　　　　rectify the resultant unreliability".
3
4　　　　　　"Ignoring the value of interconnections on the East
5　　　　　　System and ignoring the load relief available from
6　　　　　　voltage reduction and interruptible load, the optimum
7　　　　　　value of target reserve is well above 30% probably
8　　　　　　about 35% - from the standpoints of economy,
9　　　　　　reliability and financing burden. Although there is a
10　　　　　　good deal of evidence to support the view that those
11　　　　　　two alleviating factors should be ignored to balance
12　　　　　　off the numerous other unaccounted for contingencies,
13　　　　　　if they are included, an appropriate target reserve
14　　　　　　could be 30%. Even at this value the most probable
15　　　　　　value of LOLP is .019 corresponding to five reductions"
16　　　　　　of load per year."
17
18
19　10.4　　PLANNING FOR RELIABILITY IN THE
20　　　　　　TRANSMISSION SYSTEM
21
22
23　10.4.1　Introduction
24
25　　　　　　This Section discusses criteria and practices followed
26　　　　　　in planning for reliability in the bulk power
27　　　　　　transmission system. While the transmission system
28　　　　　　includes both the lines used for bulk power
29　　　　　　transmission and those used for area supply, the
30　　　　　　criteria for the bulk power transmission system are
31　　　　　　more severe and discussion of this system provides
32　　　　　　clearer illustrations of the practices which are
33　　　　　　followed to obtain reliability.
34
35　10.4.2　Northeast Power Coordinating Council
36
37　　　　　　a)　　Background - The November 1965 Power Failure
38
39　　　　　　　　　Prior to 1965, Ontario Hydro, as with most
40　　　　　　　　　utilities, had not adopted formal reliability
41　　　　　　　　　criteria for transmission planning. Rather the
42　　　　　　　　　criteria to be applied in a particular
43　　　　　　　　　transmission expansion program were decided on the
44　　　　　　　　　basis of experience and judgement.
45
46　　　　　　　　　The massive power failure of November 9, 1965, in
47　　　　　　　　　Northeastern United States and Ontario, showed the
48　　　　　　　　　need for more intensive coordination of planning
49　　　　　　　　　between interconnected utilities and for formal
50　　　　　　　　　criteria which each utility would adhere to. The
51　　　　　　　　　following quotations from a December 6, 1965
52　　　　　　　　　report of the United States Federal Power
53　　　　　　　　　Commission on the power failure give some idea of
54　　　　　　　　　the impact of the failure on society:
55

"Beginning at approximately 5:16 p.m. on November 9, 1965, most of the northeastern United States experienced the largest power failure in history. The outage lasted from a few minutes in some locations to more than a half day in others. It encompassed 80,000 square miles and directly affected an estimated 30 million people in the United States and Canada. Occurring during a time of day in which there is maximum need for power in this area of great population density, it offered the greatest potential for havoc".

"The power failure of November 9 and 10 has made a deep impression on the public because of its widespread nature and because of the difficulty and delay in discovering the origin. It should nevertheless be considered in perspective. The service standards of the industry are very high, and interruptions are, on the whole, short and infrequent. The problem arises not because service is poor but because the universal and increasing dependence of the American public on this form of energy makes any widescale interruption seriously disruptive. The prime lesson of the blackout is that the utility must strive not merely for good but for virtually perfect service".

"Massive traffic jams occurred in cities throughout the region due to the failure of traffic control signals. Lack of transportation and failure of gasoline pumps left many people stranded in downtown areas of New York City, where hotels were unable to provide accommodation on upper floors because of lack of elevator and water service. Police and fire departments were left without normal communication systems, although it was reported that many of these departments had emergency and mobile units at their disposal".

(b) Members and Objectives

As a result of this power failure the Northeast Power Coordinating Council (NPCC) consisting of the major utilities in New England and New York, and Ontario Hydro was formed in January 1966. The NPCC now comprises a total of 21 utilities including the New Brunswick Power Commission.

1   The objective of the NPCC is to assure the
2   greatest practical reliability of service to the
3   customer. It serves as a central coordinating
4   agency for the expansion plans and operating
5   procedures of the member systems.
6
7   Subsequently, eight similar coordinating groups
8   were formed to encompass most of the other
9   electric utilities in the United States and four
10 of the major utilities in Canada. These nine
11 groups are shown on Figure 10-21 and form the
12 National Electric Reliability Council (NERC).
13
14 (c) Activities
15
16 Some of the activities of the NPCC for improving
17 the reliability of the interconnected power system
18 since its formation in 1966 are summarized in the
19 following:
20
21 i) Criteria
22
23 A number of criteria for design, operation
24 and maintenance have been developed and
25 approved by member systems of the NPCC. Some
26 of the key criteria relating to the
27 transmission system are:
28
29 - Basic Criteria for Design and Operation
30 of the Interconnected Power Systems.
31 (Appendix 10-G).
32
33 - Procedure in a Major Emergency.
34 (Appendix 10-H).
35
36 - Bulk Power System Protection Philosophy.
37 (Appendix 10-I).
38
39 ii) System Analysis
40
41 The NPCC periodically examines the adequacy
42 of the system plans of the four NPCC areas
43 (New York, New England, Ontario, and New
44 Brunswick). It assesses the transmission
45 transfer capabilities within and between
46 areas and with contiguous councils. It also
47 reviews the relay protection schemes for
48 major transmission system additions.
49
50
51
52 10.0 Page 37
53
54
55

NATIONAL ELECTRIC RELIABILITY COUNCIL

ECAR East Central Area Reliability Coordination Agreement	**MAIN** Mid-America Interpool Network	**SERC** Southeastern Electric Reliability Council
ERCOT Electric Reliability Council of Texas	**MARCA** Mid-Continent Area Reliability Coordination Agreement	**SPP** Southwest Power Pool
MAAC Mid-Atlantic Area Council	**NPCC** Northeast Power Coordinating Council	**WSCC** Western Systems Coordinating Council

FIGURE 10-21

iii) Operating Procedures

Plans for outages to transmission and generation equipment or for tests which could affect power transfers between pools are reviewed in advance and coordinated as required. Policies for the amount and distribution of operating reserve capacity and for assistance in emergencies are developed and supervised by task forces of the NPCC. The performance of each area's automatic generation control is reported periodically together with the effect this control has on the total inadvertent energy accumulation by the Council.

iv) Developments of Techniques for System Analysis

A comprehensive and original study was initiated to determine the need for improved generator computer models. This included an assessment of the importance of model improvement to the accuracy of security assessment. Recommendations were made to the industry on methods of obtaining data for such improved models.

An investigation has recently been made of computer programs applying probability methods to transmission system reliability evaluation. A prototype program is being purchased and made available to the member systems for trial. Improvements are to be made to the program to enhance its abilities in expectation of making it a practical tool for power system analysis. This program is discussed in more detail later in this memorandum.

In a pioneering effort, NPCC is creating an automated data bank to store the large amount of information required to perform load flow and stability studies.

10.4.3 Design and Operation of the Bulk Power Transmission System

Key Principles

In the past ten years, three key principles have been used in the design and operation of bulk power transmission systems.

- adequate transmission should be provided so that a single probable incident will not precipitate a cascading outage resulting in major power interruptions.

- the system should be operated within limits so that a single probable incident will not precipitate cascading outages.

- plans should be made to minimize the magnitude and duration of interruptions for possible but improbable events or operating limits being exceeded by errors.

Each of these principles is discussed in more detail in the following sections.

i) Criteria for Adequate Transmission System Capacity

The criteria to which Ontario Hydro has been designing the bulk power transmission system for the East System are contained in "Basic Criteria for Design and Operation of Interconnected Power Systems". (Appendix 10-G).

These criteria embody probability in a qualitative rather than a quantitative way. They are intended to provide adequate transmission capacity so that the operator can have considerable flexibility in scheduling generation to meet constraints that may be imposed by such considerations as fuel costs or shortages, environmental regulations which may limit the operation of certain generating stations, and forced or maintenance outages of generating stations or transmission. Design studies assume applicable contractual transfers and the most severe expected load and generation conditions.

The criteria require that during and after certain specified incidents the system should:

- remain stable and voltage, line and equipment loadings remain within applicable emergency limits.

10.0 Page 39

1   -   be adequate for testing the outaged
2   element by manual reclosing without
3   adjustment of generation.
4
5   -   meet the above two conditions after any
6   critical generator unit, transmission
7   circuit or transformer has been lost,
8   assuming area power flows and available
9   generation have been adjusted between
10   outages.

11
12 The specified incidents are:

13
14   -   a permanent three phase fault on any
15   generator, transmission circuit,
16   transformer or bus section cleared in
17   normal time.

18
19   -   simultaneous permanent phase to ground
20   faults on different phases of each of
21   two adjacent circuits on a multiple
22   circuit transmission line, cleared in
23   normal time.

24
25   -   a permanent phase to ground fault on any
26   generator, transmission circuit,
27   transformer or bus section with delayed
28   clearing due to a circuit breaker, relay
29   system or signal channel malfunction.

30
31   -   loss of any element (generator,
32   transmission circuit, transformer, bus
33   section or circuit breaker) without a
34   fault.

35   -   permanent phase-to-ground fault on a
36   circuit breaker cleared in normal time.

37
38 In addition, the criteria provide that the
39 effect of certain possible but improbable
40 contingencies be studied and plans be
41 developed to minimize the spread of any
42 interruption that might result from
43 occurrence of these contingencies. These
44 include:

45
46   -   loss of the entire capability of a
47   generating station,

48
49
50
51   10.0 Page 40
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1	- loss of all lines emanating from a
2	generating station, switching station or
3	substation.
4	
5	- loss of all transmission circuits on a
6	common right of way.
7	
8	- permanent three-phase fault with delayed
9	clearing,
10	
11	- the sudden dropping of a large load or
12	major load centre,
13	
14	- the effect of severe power swings
15	arising from disturbances outside the
16	NPCC interconnected systems.
17	
18	It is neither feasible nor necessary to test
19	all elements of the power system for all of
20	the conditions outlined in the criteria.
21	From experience and judgement, power system
22	planners and operators identify the more
23	severe and reasonably probable conditions.
24	Mathematical models of the power system are
25	then used to determine if the system
26	performance is adequate under these
27	conditions. If the system is found adequate
28	for these more severe contingencies it should
29	be adequate for most contingencies.
30	
31	In addition to the criteria for the bulk
32	power system, Ontario Hydro has developed
33	criteria for the design of the area and
34	regional supply systems. These are intended
35	to result in a system which provides the
36	desired reliability for incidents which can
37	affect users' supply but are unlikely to have
38	more than a localized effect.
39	
40	The criteria attempt to assess probabilities
41	in a qualitative way and are based on the
42	principle that expenditures to improve
43	reliability should be a function of the
44	magnitude of the load interrupted, the
45	duration of the interruption and the
46	frequency of interruption. These criteria
47	are in appendices 10-J and 10-K.
48	ii) Operating Within Limits
49	
50	The facilities installed are determined eight
51	or more years in advance by the system
52	
53	
54	
55	

design. Before and after they are placed in
service a great deal of computer testing is done
to determine safe operating limits for changing
system conditions. Careful surveillance and
control is necessary to ensure that the system
is held within these limits e.g. the amount of
generation on line for system demand and
operating reserve is distributed and monitored
to ensure that if the largest unit should trip,
its output can be replaced in five minutes
without exceeding operating limits.

In Ontario Hydro, this latter responsibility
rests with the Richview System Control Centre
operators. To assist them with this, a Data
Acquisition and Computer System (DACS) is under
development with a first phase already in use.

DACS will carry out six functions:

- establish a data base from which
  measurement errors have been filtered out
  and which is capable of representing the
  existing system operating conditions in
  terms of a mathematical model.

- display appropriate data to the operators.
  The display devices consist of television
  screens, a wall size mimic diagram and
  hard-copy printouts.

- process data to assist the operators with
  decisions related to the economic operation
  of the power system.

- log and report data

- provide automatic generation control.

- process data to assist the operators in
  decisions related to the security of the
  power system.

This last function assists the operators to
maintain the system within acceptable operating
limits by

- providing a comprehensive display and
  enunciation of system conditions.

1   -   automatic checking of operating
2   conditions against operating limits with
3   enunciation of out-of-limit conditions
4   and with automatic display of possible
5   remedial actions.
6
7
8   -   automatic checking of system steady-
9   state performance for assumed line,
10   transformer and generation outages.
11
12 -   providing for simulation of control
13   actions to check their effect before
14   they are carried out.
15
16 -   providing evaluation of system
17   performance for predicted conditions.
18
19 iii) Planning for Interruptions
20
21
22 Despite the careful precautions taken in the
23 design and operation of the system, events can and
24 do occur which initiate major interruptions of
25 electric load, through cascading outages of system
26 elements. The system may then split into one or
27 more islands which are separate from the main
28 interconnected system. These islands, formed by
29 automatic operation of the protective relaying and
30 circuit breakers, may have a surplus or deficiency
31 of generation with respect to load.
32
33 When this occurs the objectives are to:
34
35 -   interrupt as little load as possible.
36
37 -   maintain as much generation as possible
38   running and connected to the system so that
39   supply to the load can be restored without
40   extensive delay.
41
42 -   minimize damage to major equipment.
43
44 -   reconnect the island to the main system and
45   restore service as quickly as possible.
46
47 Measures used in the design and operation of the
48 system to meet these objectives include:
49
50
51 10.0 Page 43
52
53
54
55

- employing turbine-generator speed governors to match generator output to the load when adequate generation is available.

- employing load shedding if the load exceeds the capacity of the generation in the island. Emergency load shedding practices are set out in Appendix 10-H.

- providing adequate and highly reliable station service, battery supplies and air storage systems. These are required to ensure that generators can be safely shut down, and that communication systems, circuit breakers, cooling devices, control systems and other essential facilities can be operated in the absence of electric supply from the power system.

- providing System Control with information needed to direct the restoration of service.

The report in Appendix 10-L describes the events that took place during one recent major disturbance.

10.4.4   Designing For Reliability

The design of an economical and reliable power system requires that in addition to providing some redundancy in the transmission elements, attention must be directed to the arrangement of the electrical connections and the provision of reliable system components.

(a)   Transmission Lines

In planning, designing and constructing a transmission line for adequate reliability careful consideration must be given to the following:

- mechanical strength should ensure that the line will not be damaged by storms of normal intensity and that for the more intense but less frequent storms the damage will be limited.

- insulation levels should provide acceptable outage rates from lightning, switching surges and power frequency overvoltages.

- skywires and counterpoise should be installed as required to limit outages from lightning.

- number of circuits installed on a structure should take into consideration the effect of failure of the structure on system reliability.

- number of lines on a right-of-way.

While the loss of all lines on a right-of-way is relatively infrequent, the consequences can be extremely severe in terms of the resultant system disturbance. This aspect needs careful consideration in line location.

(b)   Station Connections

A typical transformer station single line diagram is shown in Figure 10-22. Some of the considerations in providing reliability in the station arrangements are:

- two station service supplies are provided and connected to different points in the station so that a single incident will rarely result in the loss of the station service supply.

- each circuit is connected through two or more circuit breakers, and switches are provided for isolation of the circuit breakers. In this way the circuit can be operated with one circuit breaker out of service.

- where possible circuits are arranged so that two adjacent circuits connected to a station bus feed power into and out of the station. This arrangement tends to minimize the consequences of losing two adjacent circuits which can happen if the breaker between those circuits fails to open for a fault on one of the circuits or if a breaker to one bus is open and a fault occurs on the circuit adjacent to the other bus.

- transformers feeding the same load are connected to different positions in the station

- connections are such that a single fault and a stuck breaker will not cause cascading outages.

CIRCUIT BREAKER SERVICED BY
ELECTRIC POWER AND/OR HIGH
PRESSURE AIR SUPPLY
-OPERATED BY AUTOMATIC RELAYING
& CONTROL RELAYING, DEPENDENT
UPON STATION D.C. BATTERY SUPPLY,
AND COMMUNICATIONS FACILITIES
-OPERATES TO REMOVE EQUIP. FROM SERVICE

MOTOR OPERATED
DISCONNECT
SWITCH

BUS WORK
IN STATION

CURRENT TRANSFORMER
SUPPLIES SCALED DOWN
CURRENT TO METERING &
RELATING CIRCUITS IN
STATION

POWER LINE CARRIER
WAVE TRAP REQUIRED
FOR COMM. VIA POWER
LINE

GROUNDING SWITCH
REQUIRED FOR
SAFETY DURING
MAINTENANCE

CAPACITOR VOLTAGE
TRANSFORMER
SUPPLIES SCALED DOWN LINE
VOLTAGE TO METERING &
RELAYING CIRCUITS IN
STATION MAY ALSO BE PATH
FOR COMMUNICATIONS CHANNELS
ON POWER LINES

POWER LINE
3 PHASE CONDUCTORS ISOLATED
FROM GROUND BY INSULATOR
STRINGS SUPPORTED BY WOOD,
STEEL OR ALUMINUM STRUCTURES.
PROTECTED FROM LIGHTNING BY
ONE OR MORE GROUNDED CONDUCTORS
ABOVE THE PHASE CONDUCTORS

FACILITIES AFFECTING THE RELIABILITY
OF A BULK POWER SYSTEM CIRCUIT

FIGURE 10-22

(c) Station Equipment

Much station equipment such as transformers,
circuit breakers, current transformers, switches
etc, is manufactured by others and the utility has
only a limited influence on its detailed design.
Nonetheless the utility plays an important role in
determining the reliability of the equipment by:

- specifying voltage and current limits that
  will ensure the equipment operates within its
  ratings, under expected conditions.

- specifying ratings that are within realistic
  manufacturing capabilities.

- specifying equipment that is as simple as
  practicable.

- providing adequate information to the
  manufacturer on the conditions under which
  the equipment will operate.

- careful evaluation of proposed designs.

- providing feedback to the manufacturer on the
  actual performance of the equipment.

- factory inspection and testing.

(d) Protective Relaying

A great deal of attention is focussed on designing
protective relaying. It must rapidly detect
faults and initiate the tripping of the
appropriate circuit breakers but must not operate
unnecessarily for steady-state loading conditions
or during the rapidly changing loading conditions
which may follow a system disturbance.

Appendix 10-I, "Bulk Power Protection Philosophy",
provides more information on this aspect of
reliability design.

10.4.5 Application of Probability Techniques

The use of probability mathematics may someday provide
a quantitative determination of expected future
availability, outage frequency and duration for the
bulk power system. To completely assess the composite

10.0 Page 46

reliability of the system, the study must investigate all combinations of generation dispatches and transmission and generation outages. For each of these combinations the degree of element loading, system voltages, generation-load balance and system stability must be considered and assessed. This would require suitable component performance data and analytical techniques. Techniques available at this time permit only a small part of such an investigation.

The design and operation of transmission systems for reliability is based therefore largely on qualitative rather than quantitative assessments. This is because of the limitations in analytical techniques and component performance data. However, considerable effort is now being devoted to development of the necessary techniques and gathering of component performance data. It is expected that quantitative assessments will come into greater use in the next five to ten years.

The results of such reliability studies are usually expressed in terms of indices which attempt to reflect the effect of unreliability (e.g. megawatts interrupted, megawatt-hours not served, etc). Some of these indices have been established with a view to the possible future calculation of the socio-economic costs of unreliability. Sample applications of reliability theory to two simple problems are illustrated in Appendix 10-M.

The present status of these techniques is:

(a) Component Performance Data

In reliability calculations, a component is an item or a group of items which is viewed as an entity for purposes of reporting, analyzing, and predicting outages. Most system components are complex assemblies of many parts and their reliability performance depends on the performance of these parts.

Figure 10-23 illustrates the major parts which can affect the reliability of a transmission circuit. These include the conductors making up the three phases, the insulators, the towers and supporting structures, the skywires and the associated station facilities at each terminal of the line. Normally such station facilities will consist of a

TO 44 KV FEEDER
POSITION
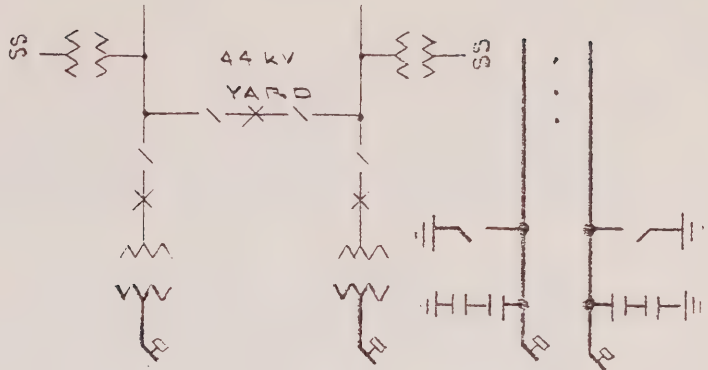
44 KV
YARD

LEGEND

44,000/600V STATION
SERVICE TRANFORMERS

230 KV 2CCT LINE

230 KV BREAKER

44 KV BREAKER

230 KV DISCONNECT
SWITCH

230 KV MOTOR OPERATED
DISCONNECT SWITCH

44 KV DISCONNECT SWITCH

230 KV GROUNDING
SWITCH

230 KV CAPACITOR
VOLTAGE TRANSFORMER

230 KV - 44KV TRANSFORM-
ERS WITH UNDERLOAD
TAP CHANGING

230 KV
YARD

TYPICAL TRANSFORMER STATION SINGLE LINE DIAGRAM

FIGURE 10-23
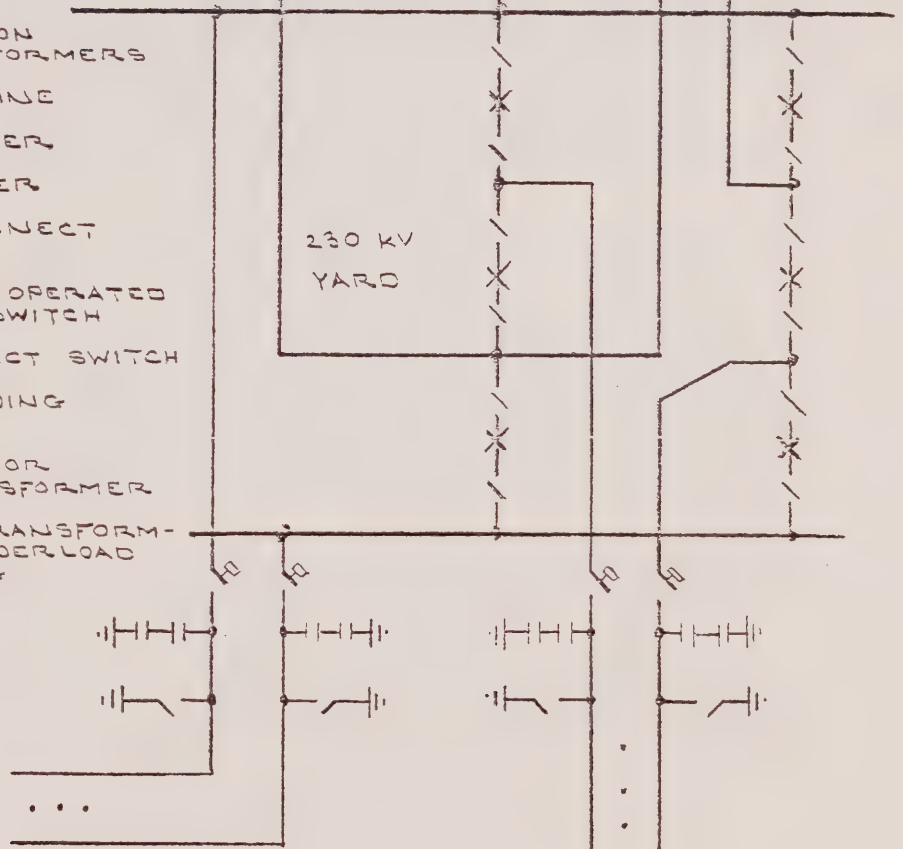
line switch, circuit breakers, circuit breaker
isolating switches, a line trap (if a power line
carrier communication system is used), current
transformers, capacitive voltage transformers,
metering equipment, protective relaying equipment
and associated communications.

If useful information for predicting future
performance is to be obtained from outage records,
a great deal of data about the circuit, the
associated station equipment, and the causes of
the outages needs to be recorded. For example, a
record only of the frequency of circuit outages
would not reveal the fact that many of the outages
were not related to the line part of the circuit,
but to the terminal equipment. Also, since
weather conditions have an important effect on
transmission circuit performance, they too need to
be part of the recorded data.

Ontario Hydro has been collecting transmission
outage statistics for many years. Recently there
has been a concentrated effort to collect and
store both forced and scheduled outage data on all
major components in a form which will be useful
for predicting future performance. Typical data
now being collected by Ontario Hydro are indicated
in Appendix 10-N and some outage data for lines
and terminal equipment are shown in Figures 10-24
and 10-25.

The historical performance of existing facilities,
will of necessity, play an important role in
predicting the future performance of new
facilities. However, the possibility that the
reliability of the new facilities may differ
significantly from that of existing facilities,
must be considered when predicting the performance
of new facilities.

(b)   Analytical Techniques

There are a number of computer programs for
assessing the reliability of the bulk power
system, which include generation system
reliability as well as transmission system
reliability in the assessment. The available
programs however suffer from one or both of the
following shortcomings:

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ONTARIO HYDRO - MAJOR TRANSMISSION OUTAGE STATISTICS

LINE OUTAGES DUE TO CONTINGENCIES ON LINE (NOT TERMINAL)

Voltage (kV)	Construction	Number of Ccts On Tower	Circuit Mile-Years	Average Line Length	Total # Line Outages		Outages Per 100 Miles Per Year	Number of Outages by Fault Type					Number of Outages by Duration (1)			Average Repair Time Perm. Faults (Hrs)	Number of Outages by Cause	
					Single Cct	Multiple Cct		L-G	L-L	LL-G	LLL	No Fault	Transient	Temporary	Permanent		Lightning	Other
500	Steel Tower	1	1531.16	113.95	20	0	1.31	18	0	0	0	2	0	10	10	40.56	3	17
500	Aluminum Tower	1	585	130	4	0	0.68	4	0	0	0	0	0	2	2	19.94	2	2
500	Subtotal		2116.16	116.24	24	0	1.134	22	0	0	0	2	0	12	12	37.12	5	19
230	Steel Tower	1	5760.25	44.48	109	0	1.69	68	0	25	12	4	28	69	12	43.03	89	20
230	Steel Tower	2	21191.48	63.71	514	36	2.77	390	126	39	10	21	167	365	54	26.77	289	297
230	Steel Tower	4	694.65	31.83	24	0	3.46	11	2	1	0	10	1	13	10	74.38	6	18
230	Wood Pole	1	3947.65	93.02	132	0	3.34	98	1	25	4	4	0	104	28	11.98	86	46
230	Subtotal		31594.03	60.77	779	36	2.694	567	129	90	26	39	196	551	104	29.24	470	351
115	Steel Tower	1	2365.86	40	255	0	10.78	155	20	49	25	6	133	108	14	10.06	160	75
115	Steel Tower	2	6383.25	35.1	455	3	7.22	258	105	58	16	24	177	236	48	14.09	199	262
115	Steel Tower	4	745.79	6.98	196	9	28.69	132	10	20	1	51	6	147	61	135.15	30	184
115	Wood Pole	1	6491.81	59.32	410	0	6.32	240	18	89	38	25	199	157	54	8.88	277	133
115	Subtotal		15986.71	37.14	1316	12	8.382	785	153	216	80	106	515	648	177	53.9	686	654

(1) Fault Durations - Transient - Fault can be reclosed successfully by automatic high-speed switching.

- Temporary - Fault can be reclosed successfully manually or automatically after time delay.

- Permanent - Fault requires repair or outage of a hour or more.

Figure 10-24

ONTARIO HYDRO - MAJOR TRANSMISSION OUTAGE STATISTICS

LINE OUTAGES DUE TO TERMINAL EQUIPMENT

Voltage (kV)	Number of Terminal Years	Total # Line Outages	Outages Per Terminal Per Year	Number of Outages by Fault Type				* No Fault	Number of Outages by Duration (1)			Average Repair Time P. m. Faults (Hrs)	Number of Outages by Location				
				L-G	L-L	LL-G	LLL		Transient	Temporary	Permanent		Bus Section (2)	Breaker	Transformer	Relaying	Other
500	31.5	111	3.52	0	0	0	0	92	0	83	28	8.4157	11	0	19	6	75
230	1245.84	1758	1.42	44	8	3	2	1544	119	1243	396	9.6340	237	3	157	95	1266
115	1385.14	1069	0.77	91	7	14	7	811	262	649	158	8.0311	203	7	139	39	681

(1) Fault Durations - Transient - Fault can be reclosed successfully by automatic high-speed switching.
    - Temporary - Fault can be reclosed successfully manually or automatically after time delay.
    - Permanent - Fault requires repair or outage of a hour or more.

(2) Fault on Bus Section includes buses, lightning arrester, PT's, CT's, etc which are not switched as part
    of a line but excludes breakers and transformers.

* These figures do not include the outages caused by transformer failure.

Figure 10-25

- assumptions are over simplified so that the model bears little resemblance to the real situation.

- assumptions are realistic and the variables adequate but the application is limited to a very small system.

The main analytical techniques now available are described briefly in the following and compared in Figure 10-26.

- Continuity Approach

This method determines the probability that there will be a continuous path between the generation and the load. It ignores circuit overloading and is applicable primarily to simple radial-type systems.

- Capacity-Flow Method

This method determines the probability of load not being supplied due to inadequate generation or transmission capacity or due to a separation of the load bus from the main system. It assumes the transmission elements can be loaded in accordance with their capacity but ignores the actual distribution of power flows.

- Load Flow Method

This method provides similar information to the foregoing but carries out load flows so that actual power distribution and network voltage levels are taken into account. Its main limitation is that the size of the system must be kept quite small to keep computer running times and costs within reason.

- Simulation Techniques

These methods use simplified load flows to obtain reasonable results, and avoid excessive computer times by selecting the conditions to be tested by a random process. These methods do not identify all the problem areas but can give some realistic assessment of the probability of load not being supplied provided enough tests are carried out.

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COMPARISON OF ANALYTICAL TECHNIQUES
FOR SYSTEM RELIABILITY ASSESSMENT

Technique	Accounts For			Remarks
	Transmission Capacity	Power Distribution	Voltage Levels	
Continuity	NO	NO	NO	Used for Radial Systems
Capacity Flow	YES	NO	NO	
Load Flow	YES	YES	YES	Limited System Size
Simulation	YES	YES	YES	Selects Conditions Investigated by Random Process
PCAP	YES	YES	NO	Selects Conditions Investigated by Sensitivity Method

NOTES: Methods listed approximately in order of increasingly complexity. No methods consider transient stability limits.

FIGURE 10-26

- <u>Composite System Reliability</u>

  The utility industry is now attempting to develop
  a means of evaluating the overall reliability of
  generation and transmission configurations. The
  aim is to provide a composite reliability index
  for every point in the system.

  Ontario Hydro is participating in this activity.
  In collaboration with other members of NPCC and
  Power Technologies Inc. it is developing the
  "Power Technologies Incorporated Fast Contingency
  Analysis Program" (PCAP). It is also carrying on
  separate studies on its own.

  The scope of these programs is described in more
  detail in Appendix 10-0.

- <u>Interface Loading</u>

  This method does not attempt to give a reliability
  index for the entire system as in the foregoing
  methods but instead focuses on the probability of
  outages at a particular interface in the system.

  In this method the system is considered as two
  subsystems. The interface separating the two
  subsystems is selected by the system planner on
  the basis of his knowledge that one or more of the
  circuits crossing the interface are likely to be
  approaching their critical loading in the time
  period being considered.

  Generation reliability techniques can be used to
  determine the probability that the interface
  loading will be above specified levels. Load
  flows and stability programs can be used to
  compare the required circuit loadings with the
  permissible loadings. Probability theory can then
  be used to determine the probabilities of
  excessive loadings on the particular interface.

  The method appears to have advantages in assessing
  the need for new transmission lines and is under
  investigation by Ontario Hydro.

10.4.6 <u>Common Cause Failures</u>

Another important consideration in transmission
planning and design is multiple unit failures resulting

from a single cause. These are often referred to as
common mode or cross-linked failures. Reference (14)
lists five general causes of such failures as follows:

- external normal environment - includes such
  factors as dust, dirt, humidity and temperature.

- equipment design deficiency - accounts for
  electrical or mechanical interpendence between
  components or subsystems.

- operation and maintenance errors - includes
  carelessness, improper adjustment or maintenance
  or other human factors.

- external phenomena - tornadoes, fire, flood and
  earthquakes.

- functional deficiency - inadequate design because
  of erroneous predictions about the behaviour or
  usefulness of variables monitored or erroneous
  predictions of the effectiveness of protective
  action to be taken.

Many common cause failures have occurred because they
were not foreseen in the original design. It can
therefore be concluded that the ability to predict
common cause failures in extensions to the electric
power system is limited. Most of the effort must be
directed to preventing such failures rather than
predicting them. Their prevention requires careful
consideration in every step of design, manufacture,
construction, inspection, testing, operating and
maintenance.

Two types of common cause failures which have occurred
on the Ontario Hydro system and were quite
unpredictable are:

- Current Transformer Failure

    In July, 1969 a 230 kV current transformer in one
    circuit at Richview TS failed in a manner which
    caused three other lines to trip, setting off a
    cascading series of trippings at other stations.
    There was forced shutdown of generation and
    extensive customer interruptions in the Toronto
    area extending up to 35 minutes.

Violent Storms

Two examples of violent wind storms are:

- In August 1970, a "severe windstorm resembling a tornado" struck the Sudbury area. It destroyed several structures on 230 kV and 115 kV lines in one area, and on a 500 kV line some miles away, putting the lines out of service for up to a week.

- In March 1976, high winds caused four towers on a 230 kV two 2-circuit line between Middleport TS and Buchanan TS to collapse. One tower fell into an adjacent 230 kV 2-circuit line breaking a skywire and two phase conductors on one circuit. Thus, all three 230 kV circuits carrying power from Middleport to Buchanan were automatically removed from service.

10.4.7 Reliability Assessment of High Voltage
Transmission System

The reliable day by day performance of the high voltage transmission system is measured by the ability of the system to maintain supply to delivery points. These delivery points are the transformer station low voltage buses, which are considered to be the interface between the high voltage transmission system and the retail or distribution system.

The two performance aspects considered are:

- the ability of all Ontario Hydro generation sources plus firm purchases to meet the total electric load.

- the ability of the bulk power system to deliver power continuously to its "delivery points".

Generation Performance

Ontario Hydro customers have not experienced interruption of supply as the result of generation shortfall for many years. There have been occasions when due to major contingencies it has been necessary to obtain emergency assistance over the interconnections. Such assistance has been obtained primarily over the US interconnections. Figure 10-27 shows the frequency of emergency purchases of power

EMERGENCY PURCHASES BY ONTARIO HYDRO
FROM USA

Year	Freq.(1)	Peak MW (2)
1968	81	550
1969	31	500
1970	12	400
1971	3	200
1972	0	0
1973	0	0
1974	1	510 (3)
1975	0	0

NOTES: (1) Freq. = frequency, number of
            occasions per year

       (2) Peak = largest MW purchase in
            any one hour

       (3) 510 MW capacity reserved.

FIGURE 10-27

made by Ontario Hydro from the interconnections with
the United States for this purpose in recent years.

Delivery Continuity

Customers are affected by service interruptions in a
complex way. This effect will vary depending upon a
number of factors.

For simplification and ease of calculation, Ontario
Hydro has selected a few indices to indicate the
continuity of supply of the high voltage transmission
system to the delivery points. Two major indices
relating to the continuity of supply are:

- the annual number of interruptions experienced by
  each delivery point,

- the annual total interruption duration experienced
  by each delivery point.

Figure 10-28 shows the system average of these indices
for the 1970-1975 period. On average a delivery point
was interrupted 1.85 times per year for a total
duration of 21.3 minutes per year. Individual delivery
point service can of course differ markedly from these
averages depending on its supply configuration. For
example during this period, interruptions to individual
delivery points averaged from zero to 14.6 per year and
interruption duration from zero to 449 minutes per
year.

These indices are calculated annually for each delivery
point and a review is made of reasons relating to
significant deviations from the average.

Since most electric utilities have not as yet developed
long term statistics from which similar indices can be
developed, Ontario Hydro has been unable to make inter-
utility performance comparisons.

Line
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SYSTEM PERFORMANCE RELIABILITY INDICES

for

ALL DELIVERY POINTS

Index	1971	1972	1973	1974	1975	Weighted Five-Year Average
System Average Interruption Frequency (Number/Year)	2.4	1.8	1.7	2.0	1.7	1.85
System Average Interruption Duration (Minutes/Year)	19	17	17	22	33	21.3

FIGURE 10-28

Line
Number

                        REFERENCES

                    Title

1. "Reliability Indices for System Customers, 1974"
    Ontario Hydro Report, July 1975

2. "A Reliability Data Handbook"
    Ontario Hydro, December 1975

3. "Distribution Systems - Annual Service Continuity
    Report of Canadian Electrical Utilities for 1973"
    Canadian Electrical Association, March 1975

4. "Cost of Interruptions in Electricity Supply"
    Swedish report from Committee on Supply
    Interruption Costs (English edition)
    September 1969

5. "Report of the Group of Experts on Quality of
    Service From the Consumer's Point of View"
    Tariff Studies Committee, Internation Union of
    Producers and Distributors of Electrical Energy
    Publication 60/D.1, 1972

6. "Report of Reliability Survey of Industrial
    Plants, Part II"
    IEEE Commiittee Report
    IEEE Transactions on Industry Applications
    March/April 1974, pp 236-241

7. "PMA-76-2, Report on the Study of
    The London Power Interruption, July 25, 1975"
    Ontario Hydro Report, March 15, 1976

8. "Fuels Supply"
    Ontario Hydro Memorandum to the Royal Commission
    on Electric Power Planning With Respect to the
    Public Information Hearings, 1976

9. "Annual Forced Outage Indices and Capacity
    Factors for Nuclear Fuelled and Fossil-Steam
    Units"
    Ontario Hydro Memorandum, G. Kirkpatrick to
    H. Teekman, April 2, 1976

10. "Reliability and Maintainability in the Design
    of Ontario Hydro Generating Stations"
    J. Krasnodebski
    A lecture prepared for the Canadian Nuclear
    Association Practical Reliability and
    Maintainability Course, April, 1976

Line Number		Title
1		
2		
3	11.	"Application of Probability Methods to
4		Generating Capacity Problems"
5		AIEE Committee Report, AIEE Paper 60-1185
6		AIEE Transactions pp 1165-1182, February, 1961
7		
8	12.	"An Approximate Quantitative Assessment
9		of Reliability, Risks, Costs and Values
10		Associated With Reserve Generating Capacity,
11		Ontario Hydro East System 1975-85"
12		Ontario Hydro Working Paper, April 1976
13		
14	13.	"Power System Reliability Evaluation"
15		R. Billenton
16		Gordon & Breach Science Publishers Inc
17		New York, 1970
18		
19	14.	"Common Mode Failure Analysis"
20		W.C. Gangloff
21		IEEE Transactions on Power
22		Apparatus and Systems pp 27-30, January 1975

LIST OF APPENDICES

APPENDIX 10-A

Seasonal Peak and Energy Characteristics of
Ontario Hydro's Generating Resources

          indicates the monthly and annual characteristics of Ontario Hydro's existing generating resources. To eliminate non-seasonal effects due to changes in the quantity of these resources throughout the year, the data are limited in two ways:

- For all resources except the 187 MW firm purchase from Hydro-Quebec, the resources shown are those in commercial service by January, 1976. Thus, the data exclude the capability of new resources forecast to come into commercial service after January, 1976.

- The resources shown exclude in all months the 187 MW firm purchase from Hydro-Quebec which expires on November 1, 1976.

As noted in Table 1, none of the data shown in this attachment takes account of the forced, planned, or maintenance outages or partial deratings of generating resources. In practice, these will occur and their effect is substantial.

The following material is provided:

	Table Number of Data for	
	East System	West System
(a) Definitions of Generating Resources	1	1
(b) 1976 Peak Resources in MW, all months	2	5
(c) 1976 Energy Resources in Average MW, all months	3	6
(d) 1976, August, December and Annual Data, and Most Frequent Mode of Operation	4	7
(e) 1976 Monthly Peak and Energy Resources in Chart Form	8	8

TABLE 1

Definitions of Generating Resources

Data for generating units are based on the following definitions:

(a) Hydraulic Resources

Peak Resource (MW)

This is the peak rating of a hydraulic unit, which is the maximum net power available to supply system load for at least 5 days per week, for daily uninterrupted periods equal to:

    i) Two hours for the East System, excluding the Sir Adam Beck plants.

   ii) Twenty minutes for the Sir Adam Beck installations.

  iii) Eight hours for all West System plants.

Energy Resource (Average MW)

This is the energy generating capability of a hydraulic unit, which is the maximum net energy available to supply system load within a month for the East System and a year for the West System.

Alternatives Shown

Hydraulic peak and energy resources are based on monthly mean river flows. They are shown for two alternative values:

    i) Dependable values, attainable or exceeded 98% of the time.

   ii) Median values, attainable or exceeded 50% of the time.

(b) Thermal Resources

Peak Resource (MW)

This is the peak rating of a thermal unit, which is the maximum net power available to supply system load for a minimum of two hours a day, without exceeding specified limits of equipment stress.

Energy Resource (Average MW)

This is the energy generation of a thermal unit, which is the maximum net energy available to supply system load within a month for the East System and a year for the West System.

The value shown is the Maximum Continuous Rating (MCR) of a unit, i.e., its design net electrical output when it is operating continuously. The rating may be adjusted after commissioning the unit.

The peak and energy capability for nuclear and fossil-steam thermal resources shown include no variation from month to month as a result of weather or environmental factors. Studies of the effects of possible regulations governing circulating water usage are under way. Their outcome may require downward revisions in the estimated capability of these resources.

The peak and energy capability of combustion turbine units reflect the effects of ambient temperature limitations.

Measurement of Resources

All peak and energy resources shown are the net outputs sent out to the system at the low voltage terminals of the step-up transformers.

No account is taken of forced, planned, or maintenance outages or partial deratings of generating units which occur from time to time.

TABLE 2 - SHEET 1

ONTARIO HYDRO - EAST SYSTEM

1976 PEAK RESOURCES IN MW, ALL MONTHS

Hydraulic - Dependable	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Abitibi Canyon	226.0	226.0	226.0	224.0	222.0	224.0	224.0	226.0	225.0	224.0	226.0	226.0
Barrett Chute	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0
Chats Falls	81.0	82.0	80.0	69.0	66.0	69.0	71.0	82.0	80.0	70.0	70.0	73.0
Chenaux	116.0	116.0	116.0	89.0	66.0	75.0	102.0	116.0	116.0	100.0	99.0	108.0
Des Joachims	372.0	372.0	359.0	336.0	314.0	330.0	364.0	372.0	370.0	362.0	363.0	367.0
Harmon	128.0	128.0	126.0	125.0	141.0	124.0	124.0	125.0	124.0	124.0	124.0	125.0
Holden	190.0	190.0	188.0	189.0	190.0	191.0	208.0	203.0	207.0	204.0	200.0	193.0
Kipling	142.0	142.0	142.0	139.0	133.0	138.0	141.0	142.0	141.0	140.0	142.0	142.0
Little Long Rapids	126.0	127.0	125.0	125.0	126.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
Mountain Chute	165.0	165.0	154.0	154.0	163.0	164.0	165.0	166.0	167.0	165.0	164.0	164.0
Niagara, SAB + PGS - CNP	1645.0	1511.0	1755.0	1341.0	1383.0	1383.0	1353.0	1343.0	1315.0	1277.0	1790.0	1745.0
Ontario Power	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	7.0	.0
DeCew Falls	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0
Otter Rapids	178.0	175.0	176.0	176.0	172.0	176.0	176.0	176.0	176.0	176.0	176.0	177.0
Aubrey Falls	158.0	158.0	153.0	153.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0
Rayner - Wells	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0
Red Rock Falls	40.0	40.0	39.0	36.0	35.0	37.0	40.0	40.0	40.0	38.0	38.0	40.0
Stewartville	168.0	168.0	168.0	167.0	167.0	168.0	168.0	169.0	169.0	168.0	168.0	168.0
Lower Notch	260.0	265.0	266.0	251.0	247.0	248.0	248.0	260.0	256.0	249.0	250.0	252.0
St. Lawrence - Saunders	790.0	784.0	790.0	660.0	662.0	687.0	710.0	716.0	710.0	694.0	693.0	696.0
Georgian Bay	29.0	29.0	29.0	29.0	29.0	29.0	29.0	30.0	29.0	29.0	29.0	29.0
Bal. In EO Div.	50.0	50.0	50.0	46.0	46.0	50.0	50.0	51.0	51.0	50.0	50.0	50.0
Bal. In NE Region	60.0	60.0	58.0	55.0	51.0	55.0	56.0	59.0	59.0	57.0	57.0	58.0
Total All Plants	5526.0	5390.0	5602.0	4966.0	4975.0	5033.0	5114.0	5161.0	5120.0	5012.0	5531.0	5498.0
Diversity	48.0	41.0	67.0	149.0	181.0	184.0	96.0	45.0	59.0	127.0	118.0	79.0
Total Hydraulic - Dependable	5574.0	5431.0	5669.0	5115.0	5156.0	5217.0	5210.0	5206.0	5179.0	5139.0	5649.0	5577.0

TABLE 2 - SHEET 2

ONTARIO HYDRO - EAST SYSTEM RESOURCES

1976 PEAK RESOURCES IN MW, ALL MONTHS

Hydraulic - Median	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Abitibi Canyon	226.0	226.0	226.0	226.0	225.0	226.0	226.0	226.0	226.0	226.0	226.0	226.0
Barrett Chute	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0
Chats Falls	84.0	84.0	84.0	77.0	74.0	81.0	84.0	84.0	84.0	84.0	84.0	84.0
Chenaux	116.0	116.0	116.0	116.0	114.0	116.0	116.0	116.0	116.0	116.0	116.0	116.0
Des Joachims	372.0	372.0	360.0	348.0	358.0	372.0	372.0	372.0	372.0	372.0	372.0	372.0
Harmon	131.0	131.0	131.0	141.0	141.0	141.0	131.0	129.0	131.0	131.0	130.0	130.0
Holden	213.0	206.0	200.0	211.0	220.0	218.0	219.0	219.0	219.0	216.0	216.0	214.0
Kipling	142.0	142.0	142.0	142.0	139.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0
Little Long Rapids	129.0	130.0	129.0	126.0	126.0	126.0	125.0	127.0	127.0	126.0	126.0	128.0
Mountain Chute	167.0	167.0	154.0	154.0	166.0	166.0	167.0	167.0	167.0	167.0	167.0	167.0
Niagara SAB + PGS - CNP	1813.0	1813.0	1813.0	1635.0	1732.0	1748.0	1750.0	1704.0	1653.0	1627.0	1844.0	1844.0
Ontario Power	105.0	105.0	105.0	.0	.0	.0	.0	.0	.0	.0	105.0	105.0
DeCew Falls	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0
Otter Rapids	179.0	179.0	178.0	178.0	179.0	178.0	178.0	179.0	178.0	179.0	178.0	179.0
Rayner - Wells	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0
Red Rock Falls	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Aubrey Falls	158.0	158.0	153.0	153.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0
Stewartville	169.0	169.0	168.0	168.0	168.0	168.0	169.0	169.0	169.0	169.0	169.0	169.0
Lower Notch	270.0	274.0	275.0	269.0	253.0	258.0	263.0	265.0	266.0	268.0	268.0	267.0
St. Lawrence - Saunders	818.0	818.0	820.0	820.0	835.0	839.0	846.0	852.0	832.0	814.0	782.0	764.0
Georgian Bay	30.0	30.0	29.0	29.0	29.0	30.0	30.0	30.0	30.0	30.0	30.0	29.0
Bal. In EO Div.	51.0	51.0	51.0	46.0	47.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
Bal. In NE Region	60.0	60.0	60.0	58.0	58.0	59.0	60.0	60.0	60.0	60.0	60.0	60.0
Total All Plants	5875.0	5873.0	5836.0	5539.0	5664.0	5719.0	5729.0	5692.0	5623.0	5578.0	5866.0	5847.0
Diversity	-6.0	-15.0	1.0	-18.0	-22.0	-23.0	26.0	15.0	24.0	14.0	.0	-10.0
Total Hydraulic - Median	5869.0	5858.0	5837.0	5521.0	5642.0	5696.0	5755.0	5707.0	5647.0	5592.0	5866.0	5837.0

TABLE 2 - SHEET 3

ONTARIO HYDRO - EAST SYSTEM

1976 PEAK RESOURCES IN MW, ALL MONTHS

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Nuclear Thermal												
Douglas Point	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0
NPD	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Pickering 1-4	2056.0	2056.0	2056.0	2056.0	2056.0	2056.0	2056.0	2056.0	2056.0	2056.0	2056.0	2056.0
Total Nuclear Thermal	2284.0	2284.0	2284.0	2284.0	2284.0	2284.0	2284.0	2284.0	2284.0	2284.0	2284.0	2284.0
Fossil-Steam Thermal												
R.L. Hearn 1-4	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0
R.L. Hearn 5	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0
R.L. Hearn 6-8	600.0	600.0	600.0	600.0	591.0	591.0	591.0	591.0	591.0	591.0	600.0	600.0
J.C. Keith 1-4	256.0	256.0	256.0	256.0	256.0	256.0	256.0	256.0	256.0	256.0	256.0	256.0
Lakeview 1-2	568.0	568.0	568.0	568.0	568.0	568.0	568.0	568.0	568.0	568.0	568.0	568.0
Lakeview 3-6	1140.0	1140.0	1140.0	1140.0	1140.0	1140.0	1140.0	1140.0	1140.0	1140.0	1140.0	1140.0
Lakeview 7-8	590.0	590.0	590.0	590.0	590.0	590.0	590.0	590.0	590.0	590.0	590.0	590.0
Lambton 1-4	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0
Nanticoke 1-4	1940.0	1940.0	1940.0	1940.0	1940.0	1940.0	1940.0	1940.0	1940.0	1940.0	1940.0	1940.0
Nanticoke 5	531.0	531.0	531.0	531.0	531.0	531.0	531.0	531.0	531.0	531.0	531.0	531.0
Lennox 2	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0
Total Fossil-Steam Thermal	8816.0	8816.0	8816.0	8816.0	8807.0	8807.0	8807.0	8807.0	8807.0	8807.0	8816.0	8816.0
Combustion Turbines												
R.L. Hearn	22.0	22.0	21.0	19.0	17.0	17.0	17.0	17.0	17.0	19.0	21.0	22.0
Lakeview	22.0	22.0	21.0	19.0	17.0	17.0	17.0	17.0	17.0	19.0	21.0	22.0
J.C. Keith	7.0	7.0	7.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	7.0	7.0
Lambton	22.0	22.0	21.0	19.0	17.0	17.0	17.0	17.0	17.0	19.0	21.0	22.0
Sarnia-Scott 1-2	33.0	33.0	31.0	29.0	27.0	27.0	27.0	27.0	27.0	29.0	31.0	33.0
Sarnia-Scott 3-4	38.0	38.0	35.0	32.0	29.0	29.0	29.0	29.0	29.0	32.0	35.0	38.0
Detweiler	75.0	75.0	70.0	64.0	58.0	58.0	58.0	58.0	58.0	64.0	70.0	75.0
A.W. Manby	59.0	59.0	54.0	50.0	45.0	45.0	45.0	45.0	45.0	50.0	54.0	59.0
Nanticoke	22.0	22.0	21.0	19.0	17.0	17.0	17.0	17.0	17.0	19.0	21.0	22.0
Pickering A	46.0	46.0	42.0	38.0	34.0	34.0	34.0	34.0	34.0	38.0	42.0	46.0
Bruce A	42.0	42.0	41.0	38.0	32.0	32.0	32.0	32.0	32.0	38.0	41.0	42.0
Total Combustion Turbines	388.0	388.0	364.0	333.0	299.0	299.0	299.0	299.0	299.0	333.0	364.0	388.0

TABLE 2 - SHEET 4

ONTARIO HYDRO - EAST SYSTEM

1976 PEAK RESOURCES IN MW, ALL MONTHS

Purchases	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bryson	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Misc. NE Region	9.0	8.7	8.6	8.1	7.7	7.2	6.7	6.9	7.6	8.2	8.7	9.3
HQ Firm Power Pur.	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0
Total Purchases	1009.0	1008.7	1008.6	1008.1	1007.7	1007.2	1006.7	1006.9	1007.6	1008.2	1008.7	1009.3

East System Resources - Total

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
With Dependable Hydraulic	18071.0	17927.7	18141.6	17556.1	17553.7	17614.2	17606.7	17602.9	17576.6	17571.2	18121.7	18074.3
With Median Hydraulic	18366.0	18354.7	18309.6	17962.1	18039.7	18093.2	18151.7	18103.9	18044.6	18024.2	18338.7	18334.3

TABLE 3 - SHEET 1

ONTARIO HYDRO - EAST SYSTEM

1976 ENERGY RESOURCES IN AVERAGE MW, ALL MONTHS

Hydraulic - Dependable	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Abitibi Canyon	89	86	95	115	169	107	98	85	79	92	87	77	98
Barrett Chute	12	13	14	18	18	13	13	12	11	12	12	13	13
Chats Falls	35	33	36	64	60	53	39	30	29	34	35	36	40
Chenaux	44	39	47	87	66	71	55	42	40	48	47	47	53
Des Joachims	136	122	144	221	201	216	160	140	134	155	148	143	160
Harmon	14	16	14	36	141	76	36	25	26	25	29	25	39
Holden	68	62	68	101	104	104	77	76	73	84	77	72	81
Kipling	15	16	14	37	133	83	37	26	27	26	31	26	39
Little Long Rapids	13	14	13	33	125	74	33	23	24	24	28	23	36
Mountain Chute	12	13	13	17	17	13	13	12	12	12	12	13	13
Niagara, SAB + PGS - CNP	963	857	1065	890	931	936	903	893	886	870	1131	1057	949
Ontario Power	0	0	0	0	0	0	0	0	0	0	0	0	0
DeCew Falls	118	87	131	84	102	103	90	87	75	57	51	131	93
Otter Rapids	42	42	47	61	93	54	47	42	36	46	46	38	50
Aubrey Falls	13	9	16	9	11	11	12	11	11	8	10	13	11
Rayner - Wells	21	20	42	22	21	20	20	17	20	20	21	22	22
Red Rock Falls	12	10	21	14	17	12	12	10	10	11	12	13	13
Stewartville	12	13	14	20	20	14	14	11	11	11	12	14	14
Lower Notch	18	20	20	29	47	33	22	20	21	20	22	20	24
Robert H. Saunders	574	568	558	572	571	598	621	628	623	606	607	614	595
Georgian Bay	15	15	16	23	11	9	6	7	10	11	11	15	12
Bal. In EO Div.	27	25	31	41	38	23	16	17	18	18	21	28	25
Bal. In NE Region	33	32	33	44	38	35	31	26	23	31	32	31	32
Total All Plants	2286	2112	2452	2538	2934	2658	2355	2240	2199	2221	2482	2471	2412
Diversity	391	341	301	232	376	458	340	303	350	337	327	314	339
Total Hydraulic - Dependable	2677	2453	2753	2770	3310	3116	2695	2543	2549	2558	2809	2785	2751

TABLE 3 - SHEET 2

ONTARIO HYDRO - EAST SYSTEM

1976 ENERGY RESOURCES IN AVERAGE MW, ALL MONTHS

Hydraulic - Median	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual*
Abitibi Canyon	128	134	146	224	224	219	157	131	146	151	156	128	162
Barrett Chute	26	30	40	50	51	34	17	18	18	19	21	24	29
Chats Falls	55	53	60	76	73	75	61	49	47	51	55	58	59
Chenaux	76	73	81	114	112	112	86	69	68	72	78	81	85
Des Joachims	234	227	243	336	350	343	246	218	222	230	244	242	261
Harmon	40	36	40	141	141	141	92	59	60	74	82	54	80
Holden	126	121	122	159	184	167	127	121	121	123	126	127	135
Kipling	41	37	42	139	139	141	97	63	65	82	89	56	83
Little Long Rapids	37	34	38	126	126	126	84	57	58	73	79	51	74
Mountain Chute	26	31	38	46	49	34	17	18	18	19	21	24	28
Niagara, SAB + PGS - CNP	1284	1276	1280	1109	1179	1186	1202	1161	1134	1131	1287	1287	1210
Ontario Power	68	34	50	37	42	42	42	42	45	45	85	90	52
DeCew Falls	131	131	131	131	131	131	131	131	131	131	131	131	131
Otter Rapids	62	64	69	129	175	113	79	66	72	79	80	64	88
Aubrey Falls	21	19	22	9	26	24	24	16	16	16	20	24	20
Rayner - Wells	33	30	67	46	50	52	44	29	29	28	42	43	41
Red Rock Falls	18	16	32	35	36	32	24	16	16	15	23	23	24
Stewartville	26	30	41	57	55	36	18	18	17	19	22	25	30
Lower Notch	30	32	36	68	107	61	38	28	28	30	34	35	44
Robert H. Saunders	636	656	674	735	750	752	760	771	748	730	696	679	716
Georgian Bay	25	26	28	28	29	23	17	15	14	16	22	26	20
Bal. in EO Div.	48	49	49	46	45	43	29	27	30	31	40	48	40
Bal. in NE Region	43	45	52	55	53	51	46	39	39	40	43	43	46
Total All Plants	3214	3184	3381	3896	4127	3938	3438	3162	3142	3205	3476	3363	3458
Diversity	-57	27	30	-112	14	-55	0	-52	69	37	0	23	-76
Total Hydraulic - Median	3157	3211	3411	3784	4141	3883	3438	3110	3211	3242	3476	3386	3382

* Annual Energy shown is the average of the arithmetic sum of the monthly energies.

TABLE 3 - SHEET 3

ONTARIO HYDRO - EAST SYSTEM

1976 ENERGY RESOURCES IN AVERAGE MW, ALL MONTHS

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual*
Nuclear Thermal													
Douglas Point	82	82	82	82	82	82	82	82	82	82	82	82	82
NPD	22	22	22	22	22	22	22	22	22	22	22	22	22
Pickering 1-4	2056	2056	2056	2056	2056	2056	2056	2056	2056	2056	2056	2056	2056
Total Nuclear Thermal	2160	2160	2160	2160	2160	2160	2160	2160	2160	2160	2160	2160	2160
Fossil-Steam Thermal													
R.L. Hearn 1-4	1144	1144	1144	1144	1147	1147	1147	1147	1147	1147	1144	1144	1146
J.C. Keith 5	254	254	254	254	254	254	254	254	254	254	254	254	254
Lakeview 1-2	2278	2278	2278	2278	2278	2278	2278	2278	2278	2278	2278	2278	2278
Lambton 3-6	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980
Nanticoke 7-8	1940	1940	1940	1940	1940	1940	1940	1940	1940	1940	1940	1940	1940
Nanticoke 1-4	485	485	485	485	485	485	485	485	485	485	485	485	485
Lennox 2	495	495	495	495	495	495	495	495	495	495	495	495	495
Total Fossil-Steam Thermal	8576	8576	8576	8576	8579	8579	8579	8579	8579	8579	8576	8576	8578
Combustion Turbines													
R.L. Hearn	20	20	19	19	17	17	16	16	17	18	19	20	18
Lakeview	20	20	19	19	17	17	16	16	17	18	19	20	18
J.C. Keith	7	7	6	6	6	6	5	5	6	6	6	7	6
Lambton	20	20	19	19	17	17	16	16	17	18	19	20	18
Nanticoke	20	20	19	19	17	17	16	16	17	18	19	20	18
Sarnia-Scott	68	68	66	61	56	56	56	56	56	60	64	67	61
Detweiler	73	73	70	64	58	58	58	58	58	64	69	72	65
A.W. Manby	57	57	53	48	45	45	45	45	45	48	53	56	50
Pickering A	40	40	39	38	34	34	32	32	34	36	39	40	37
Bruce A	38	38	37	36	30	30	30	30	30	36	37	38	34
Total Combustion Turbines	363	363	347	329	297	297	290	290	297	322	344	360	325

* Annual Energy shown is the average of the arithmetic sum of the monthly energies.

TABLE 3 - SHEET 4

ONTARIO HYDRO - EAST SYSTEM

1976 ENERGY RESOURCES IN AVERAGE MW, ALL MONTHS

Purchases	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual*
Bryson				-1	-1	-1			-1	-1		-1	-1
Misc. NE Region	5	5	5	5	5	4	4	4	5	5	5	6	5
HQ Firm Power	900	900	900	900	900	900	900	900	900	900	900	900	900
Total Purchases	905	905	905	904	904	903	904	904	904	904	905	905	904
East System Resources - Total													
With Dependable Hydraulic	14681	14457	14741	14739	15250	15055	14628	14476	14489	14523	14794	14786	14718
With Median Hydraulic	15161	15215	15399	15753	16081	15822	15371	15043	15151	15207	15461	15387	15349

* Annual Energy shown is the average of the arithmetic sum of the monthly energies.

TABLE 4 - SHEET 1

ONTARIO HYDRO - EAST SYSTEM
1976 AUGUST, DECEMBER AND ANNUAL DATA
AND MOST FREQUENT MODES OF OPERATION

(1)	(2) PEAK Dependable Mw.	(3) MONTH OF AUGUST ENERGY Dependable Av. Mw.	(4) MONTH OF AUGUST ENERGY Median Av. Mw.	(5) CAPACITY FACTOR ((3)÷(2)) %	(6) PEAK Dependable Mw.	(7) MONTH OF DECEMBER ENERGY Dependable Av. Mw.	(8) MONTH OF DECEMBER ENERGY Median Av. Mw.	(9) CAPACITY FACTOR ((7)÷(6)) %	(10) PEAK December Dependable Mw.	(11) ANNUAL ENERGY Dependable Av. Mw.	(12) ANNUAL ENERGY Median Av. Mw.	(13) CAPACITY FACTOR ((11)÷(10)) %	(14) MOST FREQUENT MODES OF OPERATION IN 1976 B	I	P	R
Hydraulic Resources																
Abitibi Canyon	226	85	131	37.6	226	77	128	34.1	226	98	162	43.4	x		x	
Barrett Chute	172	12	18	7.0	172	13	24	7.6	172	13	29	7.6		x		
Chats Falls	82	30	49	36.6	73	36	58	49.3	73	40	59	54.8	x		x	
Chenaux	116	42	69	36.2	108	47	81	43.5	108	53	85	49.1	x	x		
Des Joachims	372	140	218	37.6	367	143	242	39.0	367	160	261	43.6	x	x		
Harmon	125	25	59	20.0	125	25	54	20.0	125	39	80	31.2			x	x
Holden	203	76	121	37.4	193	72	127	37.3	193	81	135	42.0	x		x	
Kipling	142	26	63	18.3	142	26	56	18.4	142	39	83	27.5	x	x	x	
Little Long Rapids	125	23	57	18.4	125	23	51	18.4	125	36	74	28.8	x	x	x	
Mountain Chute	166	12	18	7.2	164	13	24	7.9	164	13	28	7.9		x		
Niagara SAB+PGS-CNP	1343	893	1161	66.5	1745	1057	1287	60.6	1745	949	1210	54.4	x	x	x	x
Ontario Power	0	0	42	0	0	0	90	0	0	0	52	0				
DeCew Falls	155	87	131	56.1	155	131	131	84.5	155	93	131	60.0	x	x	x	x
Otter Rapids	176	42	66	23.9	177	38	64	21.5	177	50	88	28.2	x	x	x	x
Aubrey Falls	158	11	16	7.0	158	13	24	8.2	158	11	20	7.0		x		
Rayner-Wells	275	17	29	6.2	275	22	43	8.0	275	22	41	8.0	x	x	x	x
Red Rock Falls	40	10	16	25.0	40	13	23	32.5	40	13	24	32.5		x	x	
Stewartville	169	11	18	6.5	168	14	25	8.3	168	14	30	8.3		x		
Lower Notch	260	20	28	7.7	252	20	35	7.9	252	24	44	9.5		x	x	
Robert H. Saunders	716	628	771	87.7	696	614	679	88.2	696	595	716	85.5			x	x
Georgian Bay	30	7	15	23.3	29	15	26	51.7	29	12	20	41.4				
Bal. in EO Division	51	17	27	33.3	50	28	48	56.0	50	25	40	50.0		x	x	x
Bal. in NE Region	59	26	39	44.1	58	31	43	53.4	58	32	46	55.2				
TOTAL ALL PLANTS	5161	2240	3162	43.4	5498	2471	3363	44.9	5498	2412	3458	43.9				
Diversity	45	303	-52		79	314	23		79	339	-76					
TOTAL HYDRAULIC	5206	2543	3110	48.8	5577	2785	3386	49.9	5577	2751	3382	49.3				
Nuclear Thermal																
Douglas Point	206	82	82	39.8	206	82	82	39.8	206	82	82	39.8	x		x	
NPD	22	22	22	100.0	22	22	22	100.0	22	22	22	100.0	x		x	
Pickering No 1-4	2056	2056	2056	100.0	2056	2056	2056	100.0	2056	2056	2056	100.0	x		x	
TOTAL NUCLEAR THERMAL	2284	2160	2160	94.6	2284	2160	2160	94.6	2284	2160	2160	94.6				

TABLE 4 - SHEET 2

ONTARIO HYDRO - EAST SYSTEM
1976 AUGUST, DECEMBER AND ANNUAL DATA
AND MOST FREQUENT MODES OF OPERATION

(1)	(2) PEAK Depend-able Mw.	(3) MONTH OF AUGUST ENERGY Depend-able Av. Mw.	(4) Median Av. Mw.	(5) CAPACITY FACTOR ((3)÷(2)) %	(6) PEAK Depend-able Mw.	(7) MONTH OF DECEMBER ENERGY Depend-able Av. Mw.	(8) Median Av. Mw.	(9) CAPACITY FACTOR ((7)÷(6)) %	(10) PEAK December Dependable Mw.	(11) ANNUAL ENERGY Depend-able Av. Mw.	(12) Median Av. Mw.	(13) CAPACITY FACTOR ((11)÷(10)) %	(14) MOST FREQUENT MODES OF OPERATION IN 1976 B	I	P	R
Fossil-Steam Thermal																
R.L. Hearn 1-8	1187	1147	1147	96.6	1196	1144	1144	95.7	1196	1146	1146	95.8	x	x	x	x
J.C. Keith 1-4	256	254	254	99.2	256	254	254	99.2	256	254	254	99.2	x	x		x
Lakeview 1-8	2298	2278	2278	99.1	2298	2278	2278	99.1	2298	2278	2278	99.1	x	x	x	x
Lambton 1-4	2100	1980	1980	94.3	2100	1980	1980	94.3	2100	1980	1980	94.3	x	x	x	x
Nanticoke 1-4	1940	1940	1940	100.0	1940	1940	1940	100.0	1940	1940	1940	100.0	x	x	x	x
Nanticoke 5	531	485	485	91.3	531	485	485	91.3	531	485	485	91.3	x	x	x	x
Lennox 2	495	495	495	100.0	495	495	495	100.0	495	495	495	100.0	x	x	x	x
TOTAL FOSSIL-STEAM THERMAL	8807	8579	8579	97.4	8816	8576	8576	97.3	8816	8578	8578	97.3				
Combustion Turbines																
R.L. Hearn	17	16	16	94.1	22	20	20	90.9	22	18	18	81.8			•	x
Lakeview	17	16	16	94.1	22	20	20	90.9	22	18	18	81.8			x	x
J.C. Keith	6	5	5	83.3	7	7	7	100.0	7	6	6	85.7			x	x
Lambton	17	16	16	94.1	22	20	20	90.9	22	18	18	81.8			x	x
Nanticoke	17	16	16	94.1	22	20	20	90.9	22	18	18	81.8			x	x
Sarnia - Scott	56	56	56	100.0	71	67	67	94.4	71	61	61	85.9			x	x
Detweiler	58	58	58	100.0	75	72	72	96.0	75	65	65	86.7			x	x
A.W. Manby	45	45	45	100.0	59	56	56	94.9	59	50	50	84.7			x	x
Pickering "A"	34	32	32	94.1	46	40	40	87.0	46	37	37	80.4			x	x
Bruce "A"	32	30	30	93.8	42	38	38	90.5	42	34	34	80.9			x	x
TOTAL COMBUSTION TURBINES	299	290	290	97.0	388	360	360	92.8	388	325	325	83.8				
Purchases																
Bryson	0	0	0	0	0	-1	-1	0	0	-1	-1	0				
Misc NE Region	7	4	4	57.1	9	6	6	66.7	9	5	5	55.6	x	x		
HQ Firm Power	1000	900	900	90.0	1000	900	900	90.0	1000	900	900	90.0	x			
TOTAL PURCHASES	1007	904	904	89.8	1009	905	905	89.7	1009	904	904	89.6				
TOTAL EAST SYSTEM RESOURCES	17603	14476	15043	82.2	14786	14786	15387	81.8	18074	14718	15349	81.4				

Notes: a) Peak and Energy shown are based on the definitions given in Table 1

b) B = Base Mode, I = Intermediate Mode, P = Peak Mode, R = Reserve Mode

c) Annual Dependable or Median Energy shown is the average of the arithmetic sum of the monthly dependable or median energies

TABLE 5 - Sheet 1

ONTARIO HYDRO - WEST SYSTEM

1976 PEAK RESOURCES IN MW, ALL MONTHS

Hydraulic - Dependable	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Aguasabon	43.4	41.7	41.4	42.1	44.4	45.0	45.0	44.9	45.0	45.0	45.0	45.0
Alexander	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4
Cameron Falls	74.9	74.4	74.4	74.4	74.4	74.4	74.4	74.6	75.1	75.1	75.1	75.0
Silver Falls	45.5	45.4	45.2	45.2	45.3	45.7	45.8	45.8	45.8	45.8	45.8	45.7
Caribou Falls	72.5	73.2	72.8	71.6	65.5	57.5	61.2	66.1	69.4	66.6	68.3	70.5
Ear Falls	10.8	10.2	9.4	9.1	9.9	10.8	12.1	12.5	12.5	11.2	11.2	11.1
Kakabeka Falls	18.3	18.0	19.2	18.4	22.3	19.9	17.7	16.9	16.9	17.7	18.5	18.6
Manitou Falls	59.6	59.4	59.7	59.5	59.4	53.6	58.9	59.7	59.5	59.7	59.5	59.6
Pine Portage	114.8	114.5	114.2	114.2	115.2	116.1	116.3	116.3	116.1	115.6	115.0	114.8
Whitedog Falls	50.4	51.0	50.7	49.7	45.6	39.1	42.9	46.0	47.9	47.2	47.4	49.0
Total All Plants	552.6	550.2	549.4	546.6	544.4	524.5	536.7	545.2	550.6	546.3	548.2	551.7
Diversity	23.9	22.8	23.0	25.2	22.8	23.0	28.1	32.7	28.9	29.5	26.5	27.0
Total Hydraulic - Dependable	576.5	573.0	572.4	571.8	567.2	547.5	564.8	577.9	579.5	575.8	574.7	578.7

TABLE 5 - Sheet 2

ONTARIO HYDRO - WEST SYSTEM

1976 PEAK RESOURCES IN MW, ALL MONTHS

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hydraulic - Median												
Aguasabon	45.3	45.1	44.4	44.0	44.7	45.2	45.2	45.2	45.2	45.2	45.2	45.2
Alexander	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4
Cameron Falls	75.6	75.6	75.6	75.6	75.6	75.6	75.6	75.6	75.6	75.6	75.6	75.6
Silver Falls	46.5	46.1	45.7	45.7	46.4	47.0	47.2	47.1	47.0	46.9	46.9	46.8
Caribou Falls	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8
Ear Falls	17.1	15.8	15.2	14.1	15.5	17.3	18.7	19.4	19.2	18.8	18.2	17.8
Kakabeka Falls	23.6	23.8	24.0	23.9	23.9	23.8	23.7	23.1	22.9	23.3	23.2	23.6
Manitou Falls	63.0	63.4	64.9	66.2	66.0	65.4	65.4	65.7	65.7	65.5	65.0	63.9
Pine Portage	126.8	126.3	125.2	123.6	125.3	127.8	128.9	129.3	128.9	128.0	127.4	127.2
Whitedog Falls	60.0	60.0	60.0	60.0	60.0	58.6	58.5	60.0	60.0	60.0	60.0	60.0
Total All Plants	597.1	595.3	594.2	592.3	596.6	599.9	602.4	604.6	603.7	602.4	600.7	599.3
Diversity	-3.4	-4.8	-3.6	-1.5	-4.1	-7.3	-7.5	-4.2	-3.3	-1.9	-2.9	-3.3
Total Hydraulic - Median	593.7	590.5	590.6	590.8	592.5	592.6	594.9	600.4	600.4	600.5	597.8	596.0
Nuclear Thermal												
No Nuclear Unit	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total Nuclear Thermal	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Fossil-Steam Thermal												
Thunder Bay	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0
Total Fossil-Steam Thermal	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0
Combustion Turbines												
Thunder Bay	29.0	29.0	28.0	27.0	25.0	25.0	25.0	25.0	25.0	27.0	28.0	29.0
Total Combustion Turbines	29.0	29.0	28.0	27.0	25.0	25.0	25.0	25.0	25.0	27.0	28.0	29.0
Purchases												
Manitoba Hydro	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Total Purchases	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
West System Resources Total												
With Dependable Hydraulic	902.5	899.0	897.4	895.8	889.2	869.5	886.8	899.9	901.5	899.8	899.7	904.7
With Median Hydraulic	919.7	916.5	915.6	914.8	914.5	914.6	916.9	922.4	922.4	924.5	922.8	922.0

TABLE 6 – Sheet 1

ONTARIO HYDRO – WEST SYSTEM

1976 ENERGY RESOURCES IN AVERAGE MW, ALL MONTHS

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Annual*
Hydraulic – Dependable													
Aguasabon													
Alexander													
Cameron Falls													
Silver Falls													
Caribou Falls													
Ear Falls													
Kakabeka Falls				Monthly data not available on a station basis.									
Manitou Falls													
Pine Portage													
Whitedog Falls													
Total All Plants													
Diversity													
Total Hydraulic Dependable	325	325	325	325	325	325	325	325	325	325	325	325	325

*The annual energy is that which can be provided over a year consisting of 12 consecutive months from April 1 to March 31. Because of the large hydraulic storages available, it is assumed that this annual output is available each month.

TABLE 6 – Sheet 2

ONTARIO HYDRO – WEST SYSTEM

1976 ENERGY RESOURCES IN AVERAGE MW, ALL MONTHS

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	*Annual
Hydraulic – Median													
Aguasabon													
Alexander													
Cameron Falls													
Silver Falls													
Caribou Falls													
Ear Falls													
Kakabeka Falls													
Manitou Falls													
Pine Portage													
Whitedog Falls													
Total All Plants													
Diversity													
Total Hydraulic – Median	468	468	468	468	468	468	468	468	468	468	468	468	468
Fossil-Steam Thermal													
Thunder Bay	93	93	93	93	93	93	93	93	93	93	93	93	93
Total Fossil-Steam Thermal	93	93	93	93	93	93	93	93	93	93	93	93	93
Combustion Turbines													
Thunder Bay	28	27	26	25	25	24	24	24	25	26	26	27	26
Total Combustion Turbines	28	27	26	25	25	24	24	24	25	26	26	27	26
Purchases													
Manitoba Hydro	160	160	160	160	160	160	160	160	160	160	160	160	160
Total Purchases	160	160	160	160	160	160	160	160	160	160	160	160	160
WEST SYSTEM TOTAL RESOURCES													
With Dependable Hydraulic	606	605	604	603	603	602	602	602	603	604	604	605	604
With Median Hydraulic	749	748	747	746	746	745	745	745	746	747	747	748	747

TABLE 7

ONTARIO HYDRO - WEST SYSTEM

1976 AUGUST, DECEMBER AND ANNUAL DATA

AND MOST FREQUENT MODES OF OPERATION

WEST SYSTEM	MONTH OF AUGUST				MONTH OF DECEMBER					ANNUAL			Most Frequent Modes of Operation in 1976			
	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)			
(1)	Peak Depend-able MW	Energy Depend-able Avg.MW	Median Avg.MW	Capacity Factor (3)÷(2) %	Peak Depend-able MW	Energy Depend-able Avg.MW	Median Avg.MW	Capacity Factor (7)÷(6) %	Peak December Dependable MW	Energy Depend-able Avg.MW	Median Avg.MW	Capacity Factor (11)÷(10) %	B	I	P	R
HYDRAULIC RESOURCES																
Aguasabon	44.9				45.0				45.0				x	x		
Alexander	62.4				62.4				62.4				x	x		
Cameron Falls	74.6				75.0				75.0				x	x		
Silver Falls	45.8				45.7				45.7						x	
Caribou Falls	66.1				70.5				70.5				x	x		
Ear Falls	12.5				11.1				11.1				x	x		
Kakabeka Falls	16.9				18.6				18.6				x	x	x	
Manitou Falls	59.7				59.6				59.6				x	x		
Pine Portage	116.3				114.8				114.8				x	x		
Whitedog Falls	46.0				49.0				49.0				x	x		
Total All Plants	545.2				551.7				551.7							
Diversity	32.7				27.0				27.0							
TOTAL HYDRAULIC	577.9	325	468	56.2	578.7	325	468	56.2	578.7	325	468	56.2				
FOSSIL-STEAM THERMAL																
Thunder Bay	97.0	93	93	95.9	97.0	93	93	95.9	97.0	93	93	95.9				x
TOTAL FOSSIL-STEAM THERMAL	97.0	93	93	95.9	97.0	93	93	95.9	97.0	93	93	95.9				
COMBUSTION TURBINES																
Thunder Bay	25.0	24	24	96.0	29.0	27	27	93.1	29.0	26	26	89.7				x
TOTAL COMBUSTION TURBINES	25.0	24	24	96.0	29.0	27	27	93.1	29.0	26	26	89.7				
Purchases																
Manitoba Hydro	200.0	160	160	80.0	200.0	160	160	80.0	200.0	160	160	80.0	x	x		
TOTAL PURCHASES	200.0	160	160	80.0	200.0	160	160	80.0	200.0	160	160	80.0				
TOTAL WEST SYSTEM RESOURCES	899.9	602	745	66.9	904.7	605	748	66.9	904.7	604	747	66.8				

Notes: a) Peak and Energy shown are based on the definitions given in Table 5-C-1.

b) B = Base Mode, I = Intermediate Mode, P = Peak Mode, R = Reserve Mode.

c) Annual Dependable or Median Energy shown is the average of the arithmetic sum of 12 monthly dependable or median energies starting April 1 of the year shown.

TABLE 8

MEDIAN PEAK — MW

DEPENDABLE PEAK — MW

MEDIAN ENERGY — AV. MW

DEPENDABLE ENERGY — AV. MW

ONTARIO HYDRO—EAST SYSTEM
1976 MONTHLY PEAK AND ENERGY RESOURCES

ONTARIO HYDRO—WEST SYSTEM
1976 MONTHLY PEAK AND ENERGY RESOURCES

DEPENDABLE PEAK — MW

MEDIAN ENERGY — AV. MW

DEPENDABLE ENERGY — AV. MW

MEGAWATTS

18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0

JAN   FEB   MAR   APR   MAY   JUN   JUL   AUG   SEP   OCT   NOV   DEC

GENERATION RELIABILITY INDICES

The following list of definitions are the indices used for unit and system performance. They are calculated by the "Incapability" program from the stored Thermal outage data.

(1) <u>FOR</u>

Forced Outage Rate is the ratio of forced outage hours to operating hours plus forced outage hours.

$$FOR = \frac{FO + FO(S)}{\begin{array}{c} FO + FO(S) + O + O(FD) + O(SD) \\ + SCC + SCC(FD) + SCC(SD) \end{array}}$$

FO   — Forced outage hours

FO(S)   — Sudden Forced Outage Hours

O   — Operating hours at full availability

O(FD)   — Operating hours during forced deratings

O(SD)   — Operating hours during scheduled deratings

SCC   — Synchronous condenser operation at full availability (coupled)

SCC (FD) — Synchronous condenser operation at forced derating hours (coupled)

SCC (SD) — Synchronous condenser operation at scheduled derating hours (coupled)

(2) <u>DAFOR</u>

Derating Adjusted Forced Outage Rate, this is an expansion
of the FOR and includes the effects of forced deratings
as well as forced outages, but <u>excludes</u> the effects of
Maintenance and Planned Outage Extension hours.
The DAFOR is essentially the same as the EFOR (Equivalent
Forced Outage Rate) reported by the Edison Electric Institute
on the performance of units in the USA, and is used for
comparison there with.

$$DAFOR = \frac{FO + FO(S) + O(FD)adj + SCC(FD)adj}{FO + FO(S) + O + O(FD) + O(SD) + SCC(FD) + SCC(SD) + SCC}$$

O(FD)adj   - The equivalent period of hours that a derating
           would last if considered as a forced outage.
       eg a 20% forced derating lasting for five hours is
           equivalent to a forced outage of one hour

SCC(FD)adj - similar to O(FD)adj

(3) <u>AFOR</u>

Adjusted Forced Outage Rate, this is a further expansion
of FOR and includes all the effects included in DAFOR
plus the effects of <u>including</u> Maintenance and Planned
Outage Extension hours.

$$AFOR = \frac{FO + FO(S) + O(FD)adj + SCC(FD)adj + PO(E) + MO(FE)}{FO + FO(S) + O + O(FD) + O(SD) + PO(E) + MO(FE) + SCC + SCC(FD) + SCC(SD)}$$

PO(E)   - Planned outage extension hours

MO(FE)   - Maintenance outage extension hours

(4) <u>MOF</u>

Maintenance outage factor, this is the ratio of main-
tenance outage hours (but not including extension hours)
to time in period.

$$MOF = \frac{MO \text{ hours} + MO/I \text{ hours}}{Hours \text{ in period}}$$

(5) <u>POF</u>

Planned outage factor, this is the ratio of planned outage
hours (but not including extension hours) to time in
period.

$$POF = \frac{PO \text{ hours} + PO/I \text{ hours}}{Hours \text{ in period}}$$

(6) <u>Incapability Factor</u>

This is the ratio of all types of outage hours and
equivalent hours of deratings to hours in period.

$$\text{Incapability Factor} = \frac{\begin{array}{l} FO + FO(S) + O(FD)adj + O(SD)adj + ABNO(FD)adj \\ + ABNO(SD)adj + SCC(FD)adj + SCC(SD)adj \\ + MO + MO(FE) + MO/I + PO + PO(E) + PO/I \end{array}}{Hours \text{ in Period}}$$

(7) <u>Operating Factor</u>

The percentage of total time in a specified time interval
that a unit was operating.

$$\text{Operating Factor} = \frac{\text{Operating Hours}}{\text{Hours in Period}} \times 100\%$$

(8) Sudden Forced Outage Frequency (FO(S)F)

The frequency of occurrence of sudden forced outages in the operating time normally expressed as events per operating year.

For a given generating unit:

$$FO(S)F = \frac{\text{No. of sudden forced outages per annum}}{\text{Operating Factor}}$$

(9) Capacity Factor (Gross)

The percentage of gross output that was actually produced in a specified time interval.

$$\text{Capacity Factor (Gross)} = \frac{\text{Energy Produced in Period (MWh gross}}{\text{MCR (Gross)} \times \text{Hours in Period}}$$

(10) Maximum Continuous Rating (MCR)

The design net or gross maximum electrical output for a generator operating continuously. This rating may be adjusted after commissioning the unit.

(11) Grid Incapability - GI

Grid Incapability is a unit outage caused by a component external to a particular generating station boundary such as transmission line, switch-yard, etc.

(12) Cross-Linked Outage

A cross-linked outage may be termed as an event affecting the state of two or more units simultaneously. The word simultaneously as used here has the meaning that an event affected two or more units within a four-hour period.

(13) <u>Common Mode Outage</u>

A common mode outage is an outage caused by a failure of some component that gives reasons to believe that the similar component on another unit or units might fail in identical mode, and therefore, these components must be taken out of service for inspection.

(14) <u>System Stress Event</u>

A disturbance on the Bulk Power System (BPS) which may require full or partial load rejection by a generating unit.

(a) Local system fault (eg lightning)

(b) Frequency deviations above 60.2 Hz or below 59.8 Hz

(c) Voltage deviations more than ± 10%.

APPENDIX 10-C

ILLUSTRATIVE SAMPLE

AVAILABILITY DATA KEPT FOR ONTARIO HYDRO'S
LARGE THERMAL GENERATING UNITS.

Reference (9) provides complete data for 1965-1975. The
attached charts have been selected from Reference (9) to
indicate the various types of data which are available.

Chart No.	Station,	Units	Data
4	R. L. Hearn	5 - 8	FOR, DAFOR, AFOR, ACF
9	Nanticoke	1 - 4	FOR, DAFOR, AFOR, ACF
12	Pickering	1 - 4	FOR, DAFOR, AFOR, ACF
13C			Unit Averages
14F			Total Incapability 1975
15F			Forced Outage + Forced Derating + Maintenance Outage 1975
16F			Forced Outage + Forced Derating 1975
17F			Unit Unavailability 1975
18F			Units on Forced or Maintenance Outage 1975
19F			Units on Forced Outage 1975
20F			Total Unit Unavailability 1975
21F			Units FO or MO 1975
22F			Units on Forced Outage 1975

R. L. HEARN 5-8
FOR., DAFOR., AFOR & ACF
4 x 200 MW (DPC) UNITS
(INCLUDING COMPLETE 1975 FISCAL YEAR OUTAGE DATA)

CHART 4

ACF %
AFOR %
DAFOR %
FOR %
FORECAST % AFOR

NANTICOKE 1-4   CHART 9
FOR., DAFOR., AFOR & ACF
4 × 531 MW (DPC) UNITS.
(INCLUDING COMPLETE 1975 FISCAL YEAR OUTAGE DATA)

PICKERING 1-4
FOR., DAFOR., AFOR & ACF
4 × 514 MW (DPC) UNITS.

CHART 12

UNIT AVERAGES

(INCLUDING COMPLETE 1975 FISCAL YEAR OUTAGE DATA)

CHART 13 C

CHART 14 F

1975

INSTALLED DEPENDABLE PEAK CAPACITY
THERMAL UNITS (STEAM)

10359 MW.

10350 MW

ONTARIO HYDRO THERMAL UNITS
TOTAL INCAPABILITY
1975

1975

CHART 15 F

1975

INSTALLED DEPENDABLE PEAK CAPACITY
THERMAL UNITS (STEAM)

10359 MW

10850 MW

ONTARIO HYDRO THERMAL UNITS
FORCED OUTAGE + FORCED DERATING + MAINTENANCE OUTAGE
1975

MEGAWATTS

9600 8400 7200 6000 4800 3600 2400 1200 0

JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC
1975

CHART 16 F

193

INSTALLED DEPENDABLE PEAK CAPACITY
THERMAL UNITS (STEAM)

10355 MW

10890 MW

ONTARIO HYDRO THERMAL UNITS
FORCED OUTAGE + FORCED DERATING
1975

MEGAWATTS

9600
8400
7200
6000
4800
3600
2400
1200
0

JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC

1975

ONTARIO HYDRO THERMAL UNITS
UNIT UNAVAILABILITY
1975

1975

N° OF INSTALLED THERMAL UNITS (STEAM)

35 UNITS

36 UNITS

CHART 18 F

1975

Nº OF INSTALLED THERMAL UNITS (STEAM)

36 UNITS

35 UNITS

ONTARIO HYDRO THERMAL UNITS
UNITS ON FORCED OR MAINTENANCE OUTAGE
1975

1975

CHART 19 F.

1975

Nº OF INSTALLED THERMAL UNITS (STEAM)

36 UNITS.

35 UNITS.

ONTARIO HYDRO THERMAL UNITS
UNITS ON FORCED OUTAGE
1975

UNITS

24 21 18 15 12 9 6 3 0
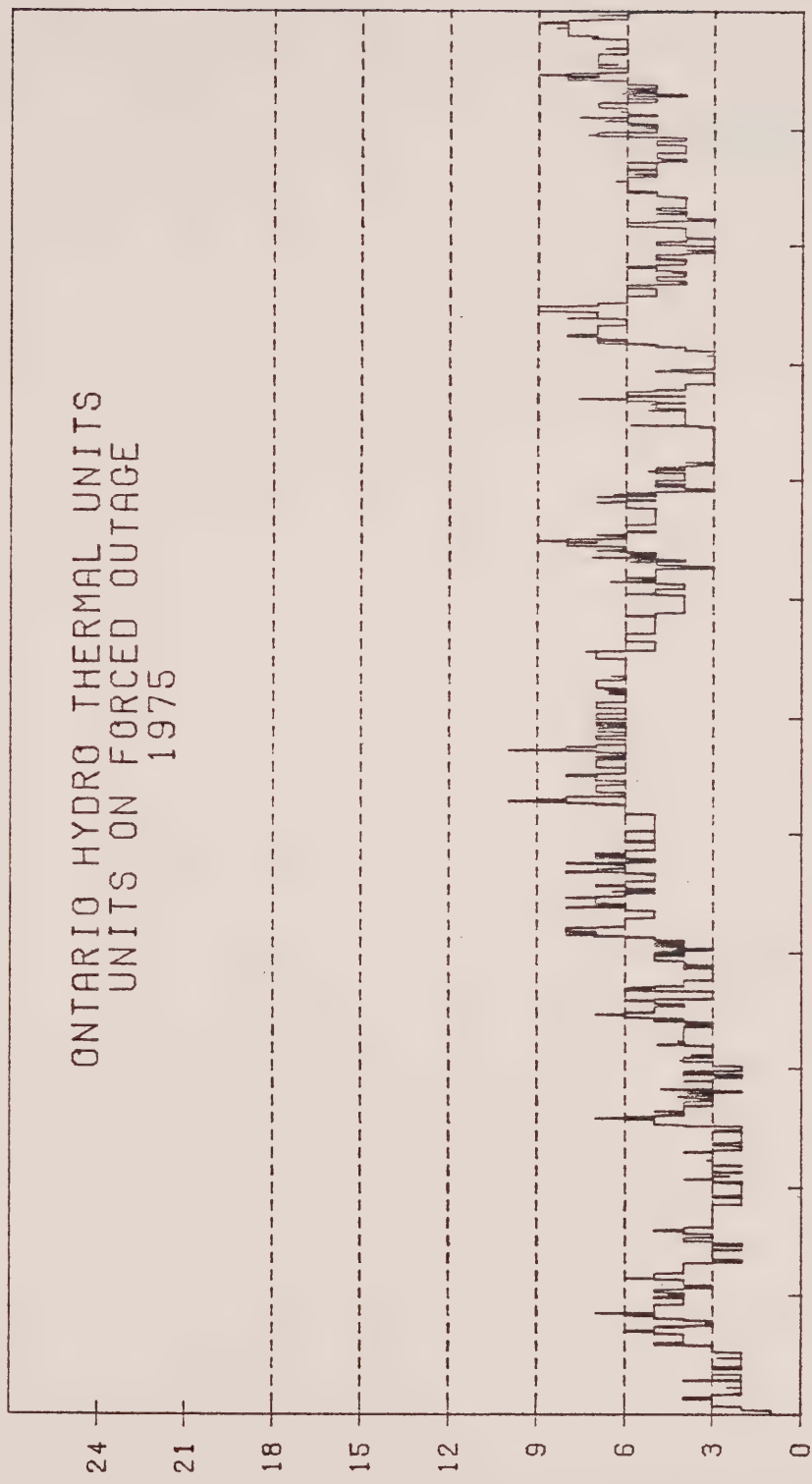
JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC

1975

ONTARIO HYDRO THERMAL SYSTEM
TOTAL UNIT UNAVAILABILITY
1975
(CALENDAR YEAR).

CHART 20 F.
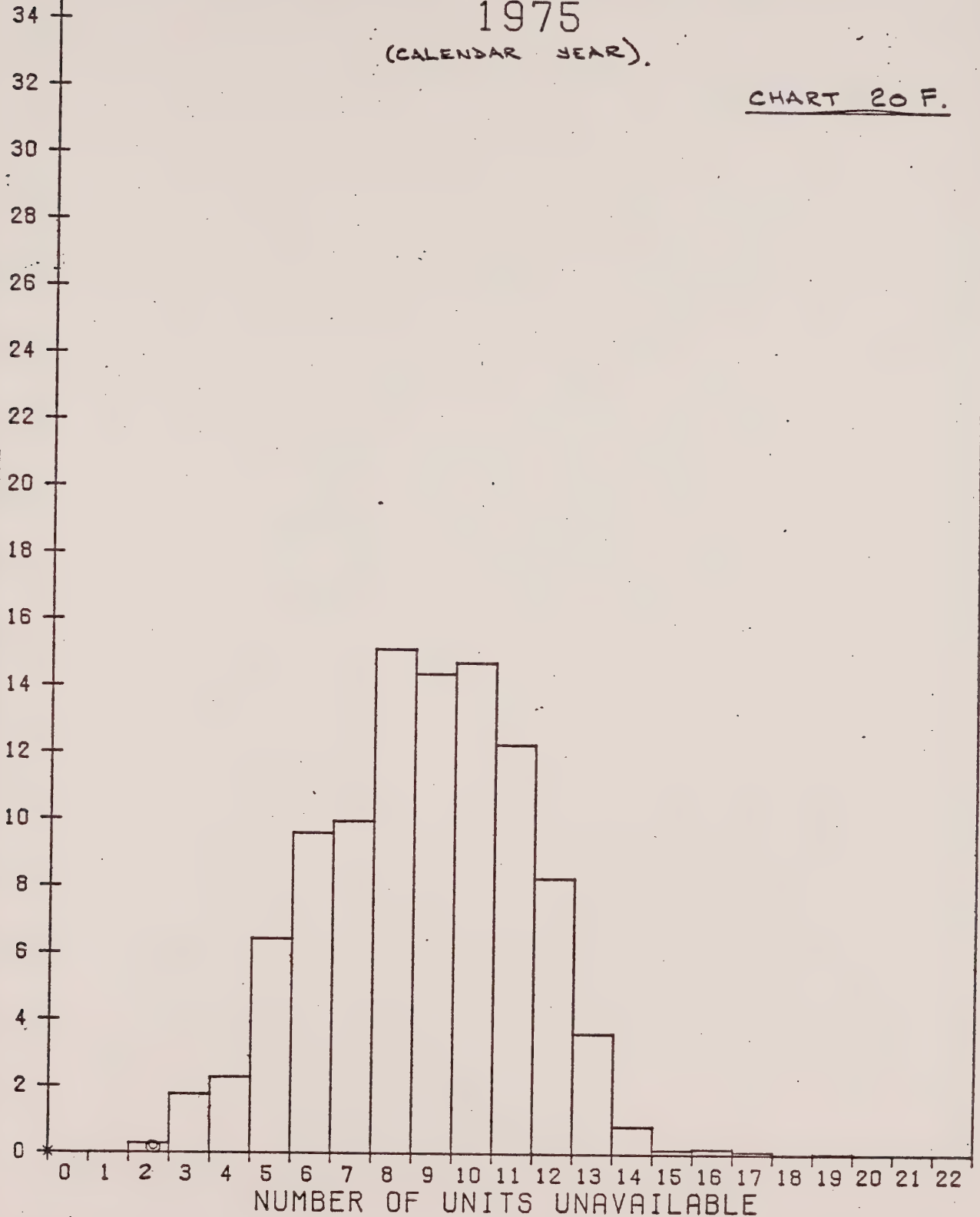
ONTARIO HYDRO THERMAL SYSTEM
UNITS ON FO OR MO
1975
(CALENDAR YEAR)

CHART 21 F.
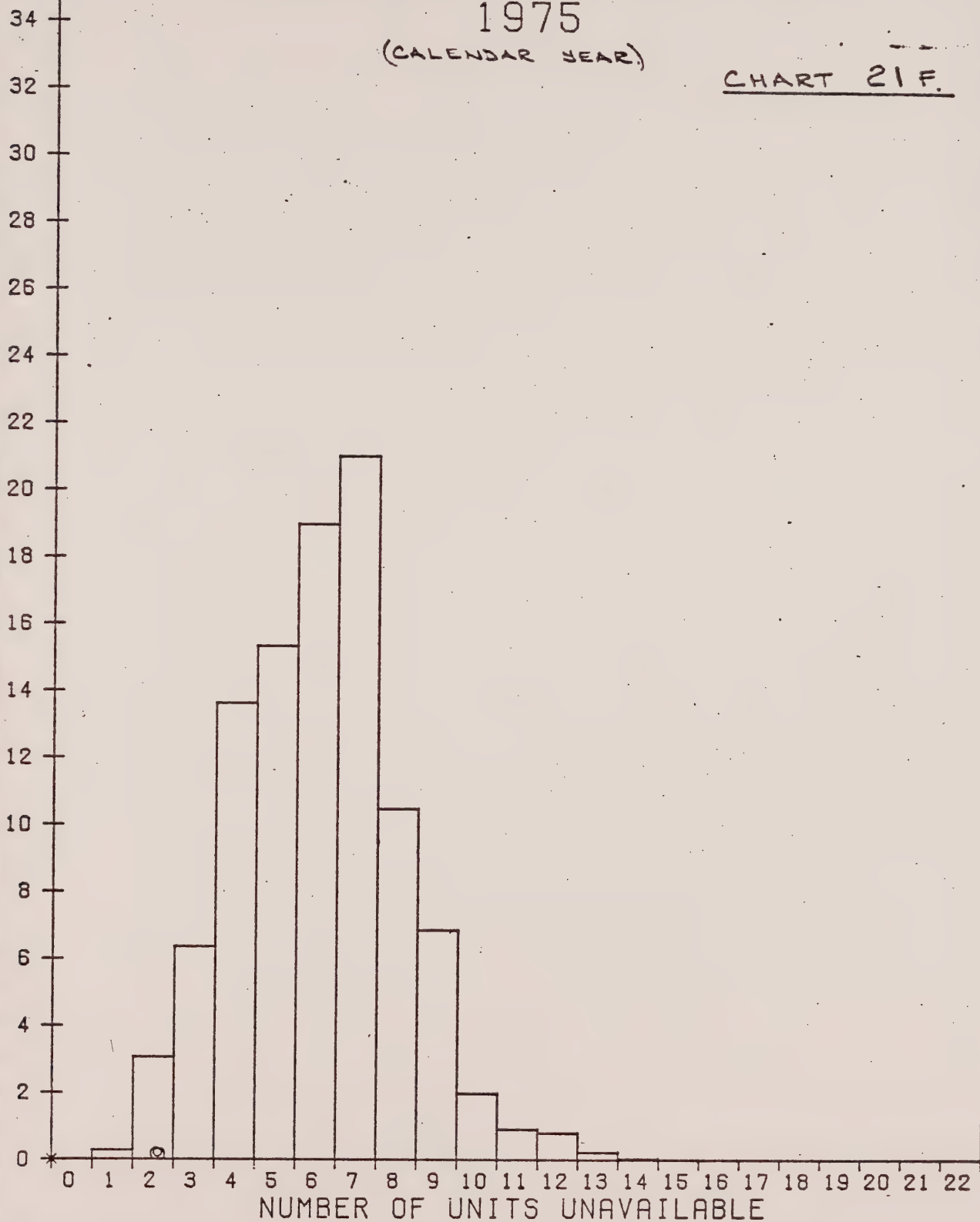
ONTARIO HYDRO THERMAL SYSTEM
UNITS ON FORCED OUTAGE
1975
(CALENDAR YEAR)

CHART 22 F
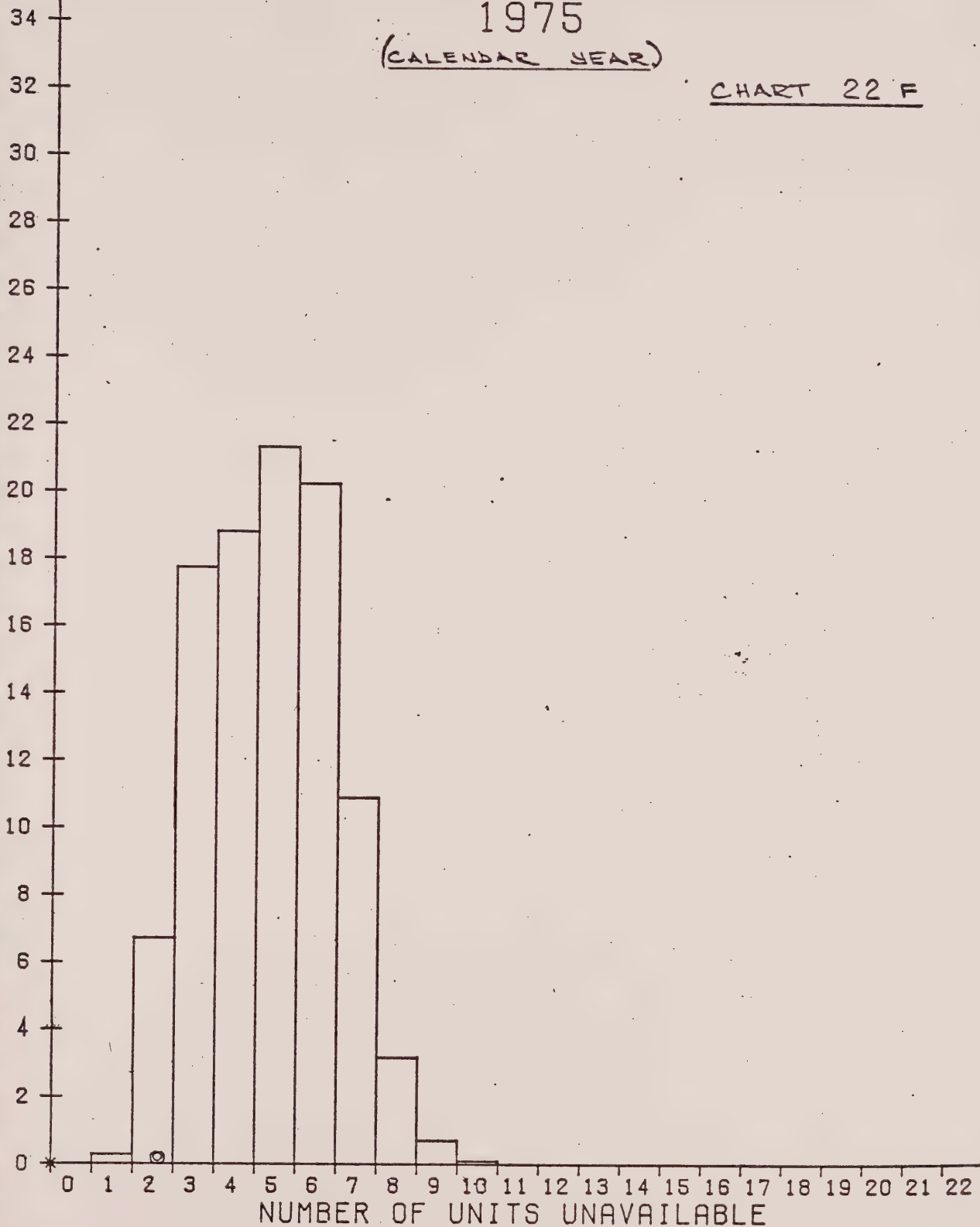
APPENDIX 10-D

<u>1976 FORECAST</u>

<u>OF</u>

<u>ADJUSTED FORCED OUTAGE RATES</u>

<u>FOR</u>

<u>CORPORATE PLANNING USE</u>

APPENDIX 10-D

1976 Forecast of Adjusted Forced Outage Rates for

Corporate Planning Use

Station	Size DPC/MCR	1976	1977	1978	1979	1980	1981	1982
Keith 1-4	64/63.5	6	6	→				
Hearn 1-4	100/96	8	8	→				
Thunder Bay	97/93	8	8	→				
Hearn 5-8	200/190	10	10	→				
Lakeview 1-2	284/284	13	13	→				
Lakeview 3	285/285	13	13	→				
Lakeview 4-5	285/285	15	15	13	→			
Lakeview 6	285/285	15	15	15	13	→		
Lakeview 7-8	295/285	14	13	→				
Lambton 1-4	525/495	5	5	→				
Nanticoke 1	531/485	12/10	10	10	→	(July)		
2	531/485	15/12	12/10	10	→	(March)		
3	531/485	12/10	10	10	→	(Dec.)		
4	531/485	12	12/10	10	→	(May)		
5	531/485	15/12	12/10	10	→	(Aug.)		
NPD	22/22	8	8	→				
Douglas Pt.	206/206	20	20	→				
Pickering 1-2	514/514	12	12	→				
3-4	514/514	15	15	15	15	15	12	→

Notes:

1) Two outage rates for a single year indicate a change in AFOR to the lower value in the month indicated

11) The AFOR applies only to the MCR rating; the increment from MCR to DPC has a 50% AFOR.

111) The corporate planning indices for "New Units" are based on a 50/50 split between leading and non-leading manufacturers. (see memo for further details)

Table 1

Mar./76

1976 Forecast of Adjusted Forced Outage Rates for

Corporate Planning Use

Station	Size DPC/MCR	1st	2nd	3rd	4th	5th	(Successive 12 Months Following I/S Date)
Nanticoke 6-8	531/485	15	12	10	↑		
Lennox * 1-2	547/495	15	12	10		↑	
3-4	547/495	12	10	8	8		
Wesleyville*1-2	547/495	15	12	10	↑		
3-4	547/495	12	10	8	8		
Bruce * 1-2	746/746	24	21	18	16	15	
3-4	746/746	19	18	17	15	↑	
Pickering 5	516/516	15	12	11	10		
6-7	516/516	14	11	10	↑		
8	516/516	12	11	10		↑	
Bruce 5-8	769/769	17	15	13	11	↑	
Darlington 1-4	850	15	13	12	10	↑	
Thunder Bay Ext	155	15	12	10	8	↑	
New Fossil 1-4	200	16.5	13.5	11.5	9.5	↑	
1-4	300	16.5	14.5	12.5	10.5	↑	
* 1-2	500	16.5	13.5	11.5	9.5	↑	
* 3-4	500	13.5	11.5	9.5	↑		
1-4	750	18.5	16.5	14.5	11.5	↑	
1-4	1000	21.5	19.5	17.5	13.5	↑	
1-4	1200	16.5	13.5	11.5	9.5	↑	
New Nuclear 1-4	200	16.5	13.5	11.5	10.5	↑	
300	300	16.5	13.5	11.5	9.5	↑	
* 1-4	600	16.5	13.5	11.5	10.5	↑	
1-4	850	16.5	14.5	13.5	11.5	↑	
1-4	1200	23.5	18.5	16.5	15.5	13.5	↑

* Numbers signify order of unit installation.

Table 1
Mar/76 cont.

1976 Forecast of Maintenance Outage Factors for

Corporate Planning Use

Station	Size DPC/MCR	1976	1977	1978	1979
Keith 1-4	64/63.5	1	1	↑	
Hearn 1-4	100/96	1	1	↑	
Thunder Bay	97/93	3	3	↑	
Hearn 5-8	200/190	2	2	↑	
Lakeview 1-2	284/284	5	5	↑	
Lakeview 3-6	285/285	5	5	↑	
Lakeview 7-8	295/285	4	4	↑	
Lambton 1-4	525/495	5	5	↑	
Nanticoke 1-5	531/485	5	5	↑	
NPD	22/22	1.5	1.5	↑	
Douglas Pt	206/206	4	4	↑	
Pickering 1-4	514/514	3	3	↑	

Table 2

Mar/76

1976 Forecast of Maintenance Outage Factors for

Corporate Planning Use

Station	Size DPC/MCR	1st	2nd	3rd	4th	5th	(Sucessive 12 Months Following I/S Date)
Nanticoke 6-8	531/485	5	5	↑			
Lennox 1-4	547/495	6	4	↑			
Wesleyville 1-4	547/495	6	4	↑			
Bruce 1-2	746/746	10	8	6	4	↑	
3-4	746/746	8	6	4			
Pickering 5-8	516/516	6	4	↑			
Bruce 5-8	769/769	8	6	4	↑		
Darlington 1-4	850	8	6	4	↑		
Thunder Bay Ext	155/150	6	5	4	↑		
New Fossil 1-4	200	6.5	5.5	4.5	↑		
1-4	300	6.5	5.5	4.5	↑		
1-4	500	6.5	4.5	↑			
1-4	750	7.5	5.5	↑			
1-4	1000/1200	8.5	6.5	↑			
New Nuclear 1-4	200/300	6.5	4.5	↑			
1-4	500/600	6.5	4.5	↑			
1-4	850	8.5	6.5	4.5	↑		
1-4	1200	8.5	8.5	6.5	5.5		

Note: The corporate planning indices for "New Units" are based on a 50/50 split between leading and non-leading manufacturers.

(see memo for further details)

Table 2
Mar/76 cont

1976 Forecast of Planned Outage Factors for

Corporate Planning Use

Station	Size DPC/MCR	1976	1977	1978	1979			
Keith 1,3	64/635	10	10	→				
2	64/635	8	10	→				
4	64/635	25	10	→				
Hearn 1-2	100/96	2	10	→				
3,4	100/96	15	10	→				
Thunder Bay	97/93	63	10	→				
Hearn 5,7	200/190	15	10	→				
6,8	200/190	2	10	→				
Lakeview 1-2	284/284	8	10	→				
3	285/285	10	10	15	10			
4	285/285	13	10	10	15	10		
5	285/285	15	10	10 →	15 →		10 →	
6	285/285	10	15	10 →	15 →			
7-8	295/285	6	10	→				
Lambton 1	525/495	13	10	→				
2,4	525/495	6	10	→				
3	525/495	8	10	→				
Nanticoke 1-2	531/485	4	10	→				
3	531/485	12	10	→				
4	531/485	13	10	→				
5	531/485	10	12	10	→			

Table 3

Mar/76

1976 Forecast of Planned Outage Factors for

Corporate Planning Use

Station	Size DPC/MCR	1976	1977	1978	1979	
NPD	22/22	6	6			
Douglas Pt	206/206	12	10	↑		
Pickering 1	514/514	8	8	↑		
2	514/514	8	8	10	8	↑
3	514/514	8	12	8	↑	
4	514/514	0	8	↑		
		1st	2nd	3rd	4th	5th (Successive 12 Months Following I/S Date)
Nanticoke 6-8	531/485	15	12	10		
Lennox 1-4	547/495	15	12	10	↑	
Wesleyville 1-4	547/495	15	12	10	↑	
Bruce 1-4	746/746	14	10	↑	↑	
Pickering 5-8	516/516	12	10	8		
Bruce 5-8	769/769	14	10	↑	↑	
Darlington 1-4	850	14	10			
Thunder Bay Ext	155	12	10	8	↑	
New Fossil 1-4	200	12	10	8	↑	
1-4	300	12	10			
1-4	500/700	15	12	10	↑	
1-4	1000/1200	15	12	10	↑	
New Nuclear 1-4	300	12	10	8	↑	
1-4	500/600	12	10	8	↑	
1-4	850/1200	14	10	↑		

Table 3
Mar/76 cont.

TABLE 4

Outage Rates of Hydraulic and Small Thermal *
Units used in System Planning Studies

Adjusted Forced Outage Rate		Planned & Maintenance Outage (Yearly Average)
Hydraulic Units	.5%	2 weeks
Small Thermal* Units	15%	5½ weeks

Note: In Loss of Load Computations for the East System the forced outage rate of the above units is set to zero. This reduces the computational effort without significantly affecting the result. For the West System the above rates are used.

* Small Thermal Units included - combustion turbines
                                 - diesels

System Planning

APPENDIX 10-E

ONTARIO HYDRO THERMAL UNITS
TOTAL INCAPABILITY 1970 - 1975

Chart	Year
14A	1970
14B	1971
14C	1972
14D	1973
14E	1974
14F	1975

1970

INSTALLED DEPENDABLE PEAK CAPACITY.

THERMAL UNITS (STEAM)

6179 MW.

5654 MW

5123 MW

4604 MW.

ONTARIO HYDRO THERMAL UNITS
TOTAL INCAPABILITY
1970

MEGAWATTS

9600 — 8400 — 7200 — 6000 — 4800 — 3600 — 2400 — 1200 — 0

JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC
1970

ONTARIO HYDRO THERMAL UNITS
TOTAL INCAPABILITY
1971

ONTARIO HYDRO THERMAL UNITS
TOTAL INCAPABILITY
1972

INSTALLED DEPENDABLE PEAK CAPACITY
THERMAL UNITS (STEAM)

7207 MW   7721 MW

MEGAWATTS

0 1200 2400 3600 4800 6000 7200 8400 9600

JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC
1972

ONTARIO HYDRO THERMAL UNITS
TOTAL INCAPABILITY
1973

1973

INSTALLED DEPENDABLE PEAK CAPACITY
THERMAL UNITS (STEAM)

9828 MW.

9297 MW

8766 MW

8252 MW
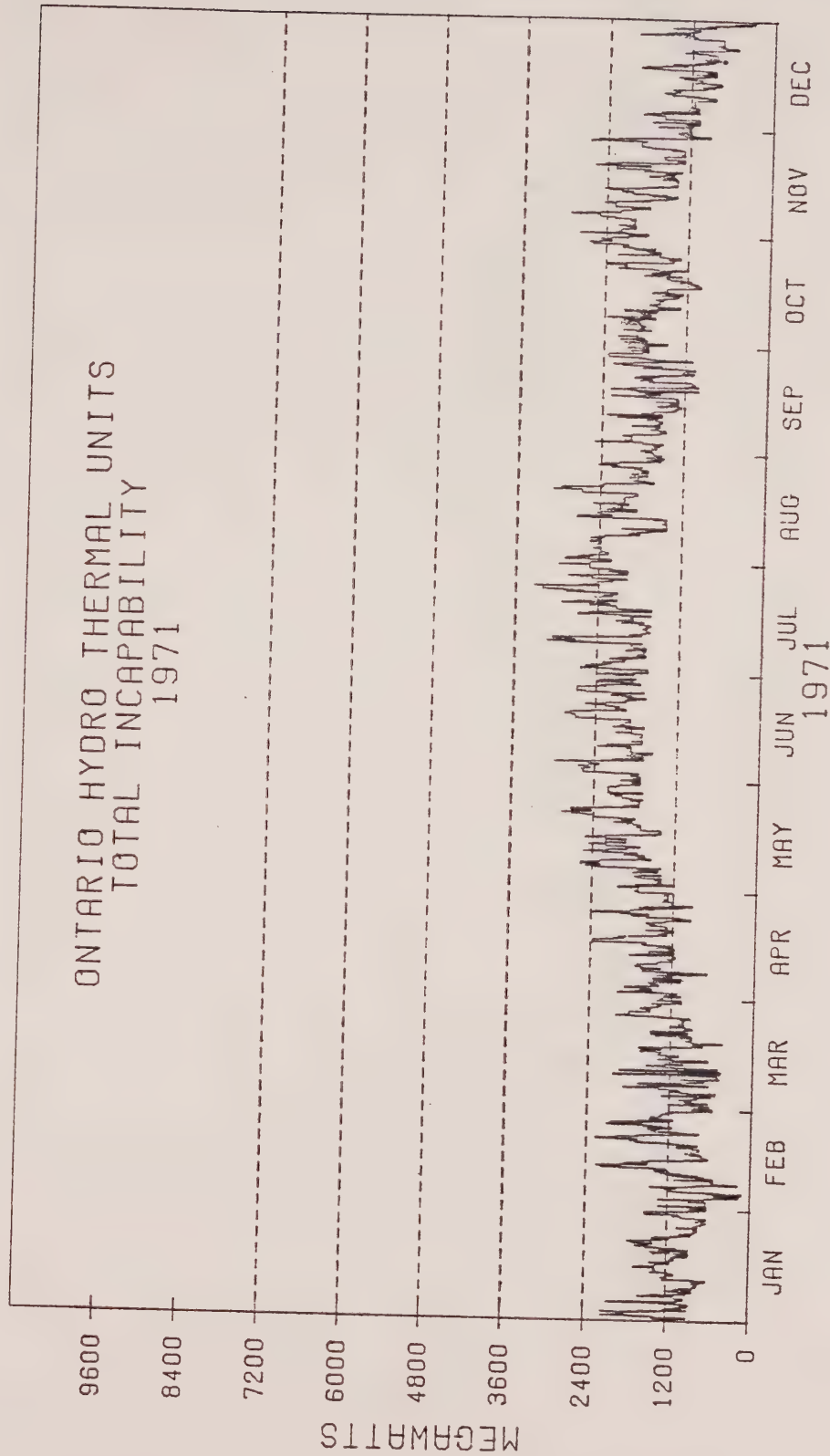
7721 MW

MEGAWATTS
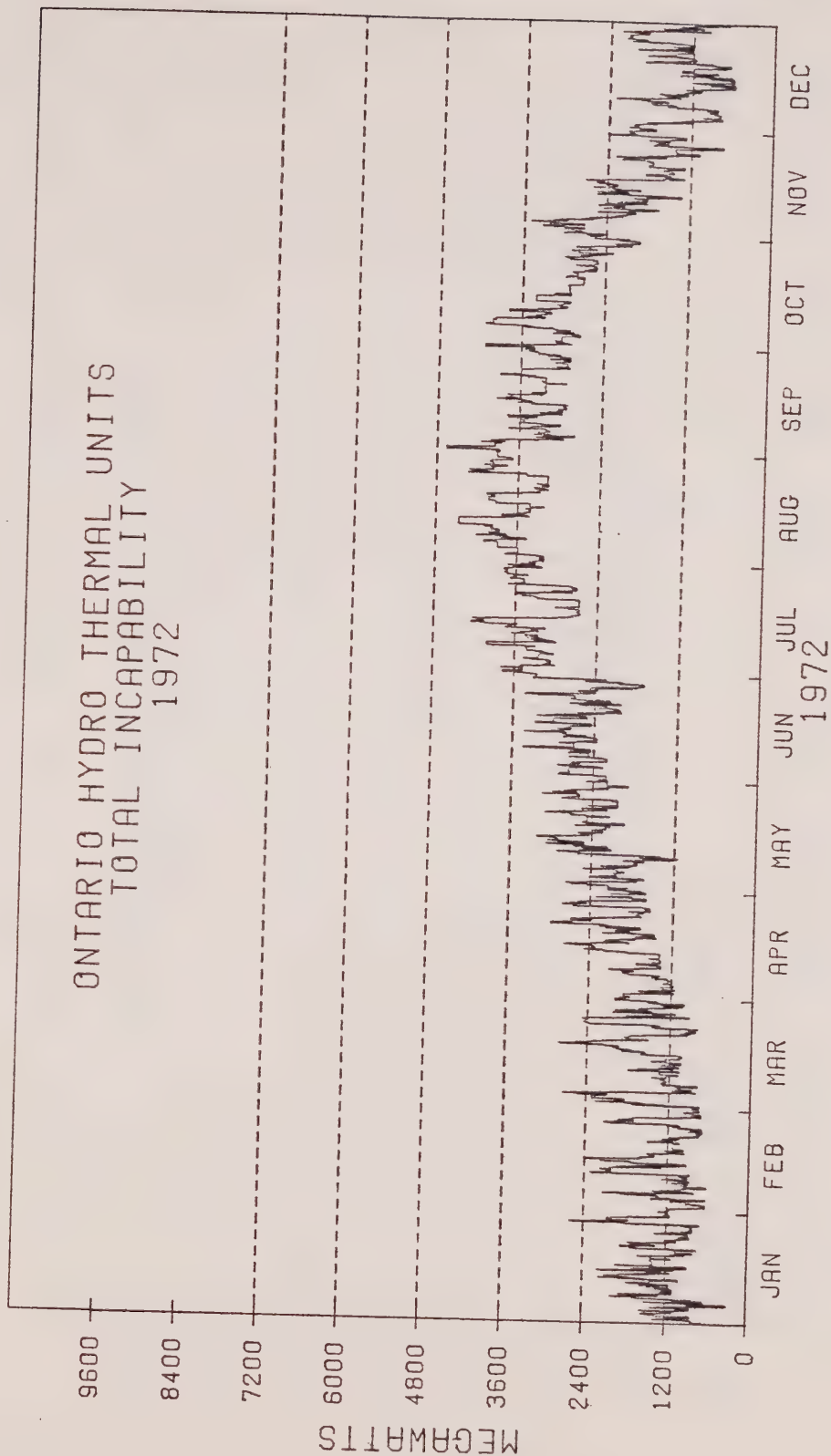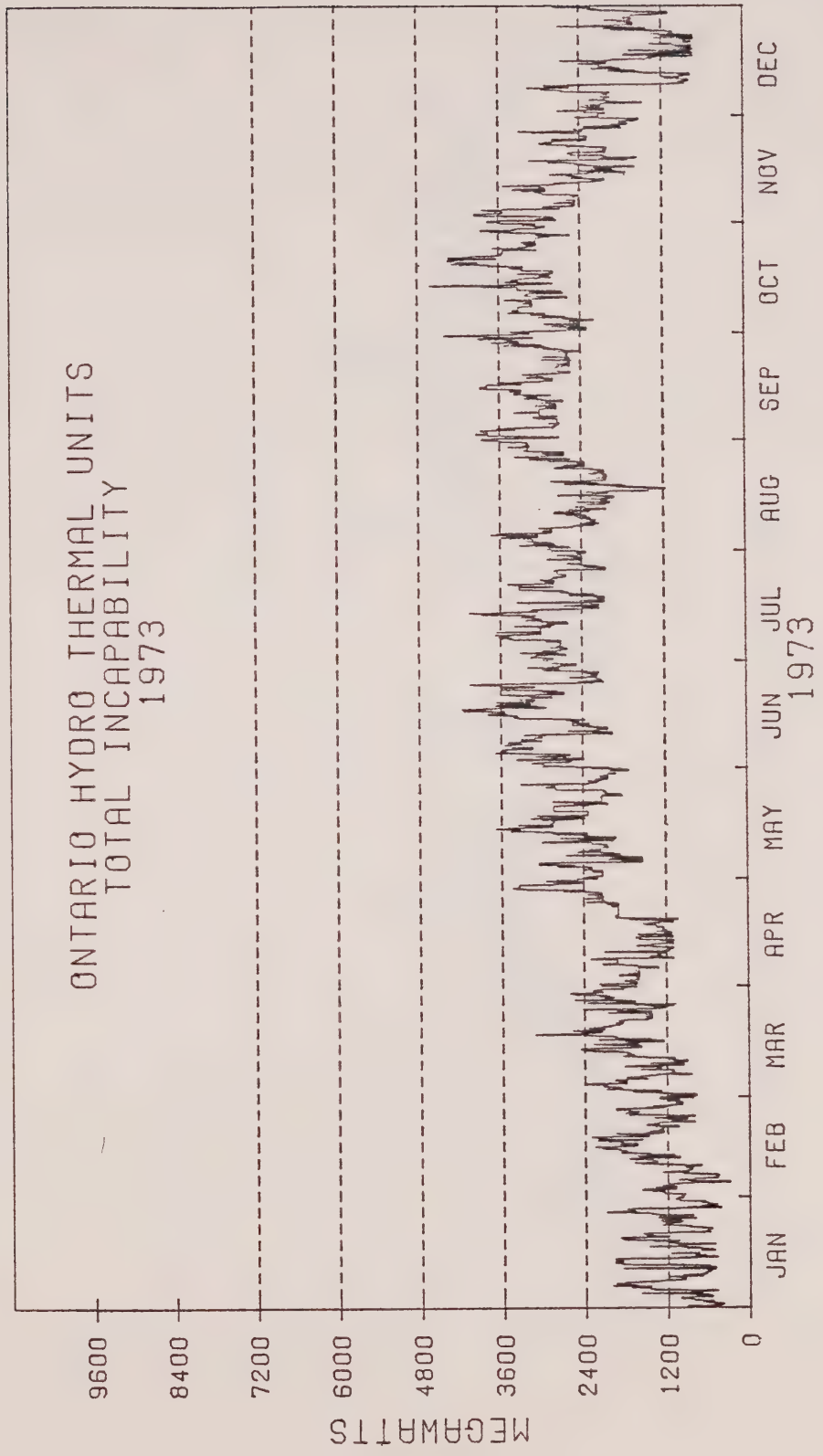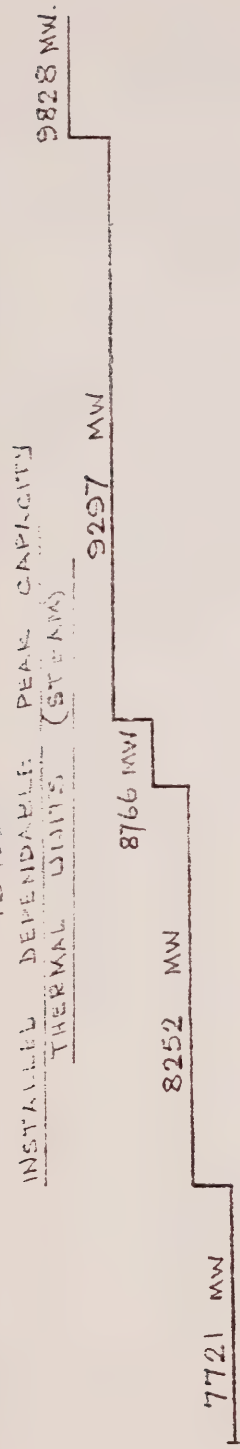
1974

INSTALLED DEPENDABLE MAX CAPACITY
THERMAL UNITS (STEAM)

10359 MW

9828 MW

ONTARIO HYDRO THERMAL UNITS
TOTAL INCAPABILITY
1974

MEGAWATTS

9600   8400   7200   6000   4800   3600   2400   1200   0

JAN   FEB   MAR   APR   MAY   JUN   JUL   AUG   SEP   OCT   NOV   DEC
1974

1975

INSTALLED DEPENDABLE PEAK CAPACITY
THERMAL UNITS (STEAM)

10359 MW   10850 MW

ONTARIO HYDRO THERMAL UNITS
TOTAL INCAPABILITY
1975

MEGAWATTS

9600
8400
7200
6000
4800
3600
2400
1200
0

JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC

1975
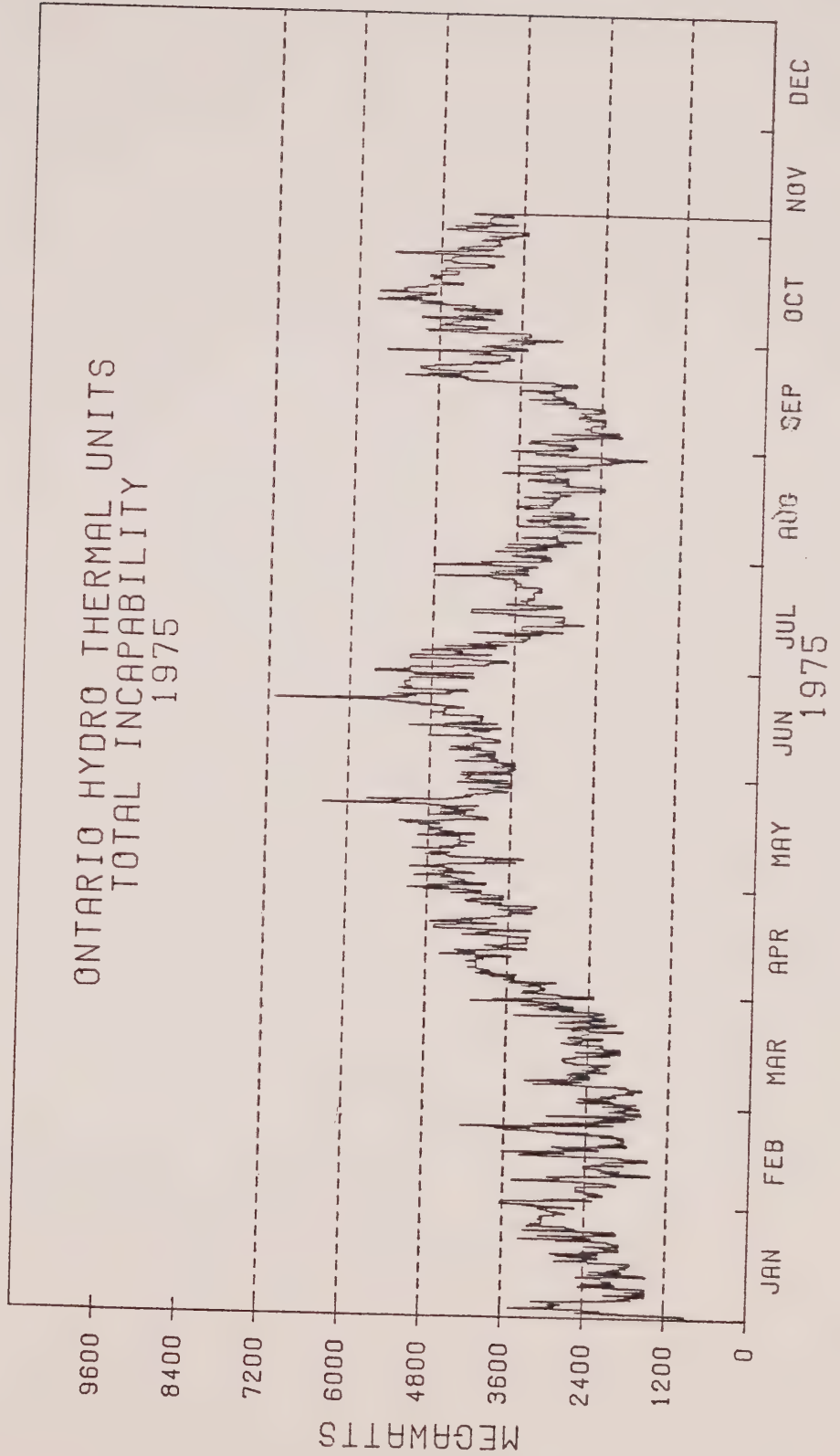
APPENDIX 10-F

ONTARIO HYDRO'S LOLP COMPUTATION

This appendix describes the Loss-of-Load Probability (LOLP) computation used by Ontario Hydro to assist in determining required reserve generating capacity.

Ontario Hydro's computation is similar in principal to, but different in details from, LOLP computations that are made by other large utilities in North America. It includes the following steps, for each month in the period under study:

(1) Estimate the peak loads on each of the normal working days in the month.

(2) Estimate the generating units that will be out of service for planned maintenance. Hence derive the generating units that are potentially capable of being operated.

(3) For the units that are potentially capable of being operated, estimate the total capacity that will be fully operable, after taking account of forced outages and deratings. This estimate is done on a probability basis, using a mathematical model. The input to the model is a listing for each generator of its peak output capacity and its estimated characteristics of forced outages and forced deratings. The output from the model is a listing for the total generation on the system showing the probability that various total amounts of generation will be in an operable condition.

Ontario Hydro's computation for its East System takes account of the variability in output of the Sir Adam Beck-Niagara hydraulic generating complex, and of forced outages and deratings of thermal units. Because these have only a minor effect, it takes no account of the variability in peak output of other hydraulic stations, or forced outages and deratings of any hydraulic units and gas turbines. Except in December and January in the case of the Quebec purchase, no account is taken of possible failures in firm power purchases from Quebec and Manitoba.

Ontario Hydro's computation for its West System does take account of the forced outages of hydraulic and gas turbine units.

(4) Combine the peak load estimates from (1) with the probability of having operable generation from (3), to compute the probability that insufficient operable generation will be available to supply the daily peak loads throughout the whole month. This is the Loss of Load Probability (LOLP).

The probability can be expressed as a per cent, decimal, or ratio. Typically it is expressed as a ratio using the number of normal working days in 5 or 10 years as the denominator. Ontario Hydro uses 10 years, for which it assumes that the number of normal working days is 2400. In the recent past, it has planned generation to meet a LOLP of about 1 in 2400 in December. This implies that, if all months are similar to December, on the average, for 1 day in 10 years generation will be inadequate to supply the total estimated firm load.

The LOLP computation as it is used at present has shortcomings, as can be seen from the fact that:

It accounts for:

It does not account for:

(a) Estimated forced outages and deratings of major generating units, assuming the operating state of each unit is independent of the states of all other units.

(a) Forced outages and forced deratings of major units which occur coincidentally or which overlap with one another because they are interrelated. The effects of these events can be substantial, but it is difficult to estimate their probability of occurrence.

(b) Estimated planned outages and deratings.

(b) Estimated maintenance outages and maintenance deratings. It is assumed that these can be completed on weekends, although this is sometimes impossible. It is also assumed that weekend generation reserves will be large because the load levels are substantially lower on weekends than other days. This situation may change in the future.

(c) Variations in hydraulic outputs at Sir Adam Beck-Niagara GS due to normal river flow variations.

(c) Variations in hydraulic outputs at other stations or at Sir Adam Beck-Niagara GS due to severe icing or wind conditions.

(d) Variations in the outputs of gas turbine and steam turbine units due to normal changes in temperature.

(d) Variations in these outputs due to extreme temperatures.

(e) Reductions in generating unit outputs due to known government regulations.

(e) Reductions in generating unit outputs due to unforeseen government regulations.

(f) Cutting of interruptible loads.

(f) Conversion of interruptible loads to firm loads.

(g) The possibility that new generation will come into service ahead of schedule or behind schedule.

(h) Strikes.

(i) Shortages of critical materials such as fossil fuels, nuclear fuels, heavy water, lubricating oils, etc.

(j) Transmission being inadequate to transmit power from the generators to the users.

(k) The energy production limitations at hydraulic stations.

(l) The possible failure of Quebec or Manitoba to deliver contracted firm power, except in the case of Quebec deliveries in December and January.

(m) Malicious damage.

(n) Actual firm peak loads being greater or less than forecast.

(o) The possible reduction in load by lowering supply voltages to users.

(p) The possible assistance available from other utilities by virtue of the interconnections.

(q) Actual forced, maintenance and planned outages and deratings being greater or less than forecast.

It is theoretically possible to include in the LOLP computation many of the factors not now accounted for. Some of the factors can be readily included in the computation. But for others, a major obstacle in including them arises from the difficulty, and in some cases the impossibility, of assigning appropriate probability factors to the events and in assessing all the ramifications of the events. However, many of the events from time to time do occur and result in major reductions in the capability of Ontario Hydro's generation.

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BASIC CRITERIA FOR
DESIGN AND OPERATION
OF INTERCONNECTED
POWER SYSTEMS

Originally adopted by the members
of the Northeast Power Coordinating
Council, September 20, 1967. Revision
adopted by the members of the Northeast
Power Coordinating Council, July 31, 1970.
Revision adopted by the members of the
Northeast Power Coordinating Council,
June 6, 1975.

C O N T E N T S

1. INTRODUCTION

The purpose of the Northeast Power Coordinating Council is
to improve the reliability and efficiency of the interconnected
power systems of its members through improved coordination in
system design and operating procedures.

One of the steps in reaching this objective is the develop-
ment of criteria that will be used in the design and operation
of the major interconnected power systems. Definitions of sev-
eral terms used in the following paragraphs are listed in the
Appendix.

It is recognized that more rigid criteria will be applied
in some segments of the Council area because of local consider-
ations. It is also recognized that the basic criteria are not
necessarily applicable to those elements of the individual mem-
bers' systems that are not a major part of the interconnected
transmission network.

The transmission criteria are applicable either to the areas
(New Brunswick, New England, New York or Ontario) or to the en-
tire Council interconnection in its relations with neighboring
"pools".

An interconnected power system should be designed and oper-
ated at a level of reliability such that the loss of a major
portion of the system would not result from reasonably foresee-
able contingencies. In determining this reliability, it would
be desirable to give consideration to all combinations of con-
tingencies occurring more frequently than once in some stipula-
ted number of years. However, sufficient data and techniques

are not available at the present time to define all the contingencies
that could occur or to assess and rank their probability of occurrence.
Therefore, it is proposed that the interconnected power systems be
designed and operated to meet certain specific contingencies. Loss
of small portions of the system (such as radial portions) may be tol-
erated, provided that these do not jeopardize the integrity of the
over-all interconnected power systems.

The following criteria for design and operation of interconnected
power systems define area generation and transmission requirements.
In addition, criteria for determining inter-area transmission transfer
capabilities are defined.

Two categories of transmission transfer capabilities are to be
considered: normal and emergency. Normal conditions are to be as-
sumed unless an emergency, as defined by Item 2 in the "List of Defini-
tions", exists.

Design studies will assume applicable contractual transfers and
the most severe expected load and generation conditions. Operating
transfer capability studies will be based on the particular load and
generation pattern expected to exist for the period under study. All
reclosing facilities will be assumed in service unless it is known
that such facilities have been rendered inoperative.

2. GENERATING CAPACITY

Generating capacity will be installed and located in such a
manner that after the due allowance for required maintenance and
expected forced outages, each area's generating supply will equal
or exceed area load at least 99.9615 percent of the time. This is
equivalent to a "loss-of-load probability of one day in ten years".

3. AREA TRANSMISSION REQUIREMENTS

The power system should be designed with sufficient transmission capacity to serve area loads under the conditions noted below. The power system should also be operated in such a manner that the design objectives are fulfilled.

3.1 Stability Conditions

Stability of the interconnected power systems shall be maintained during and after the most severe of the conditions stated in a, b, c, d, and e below. Also, the system must be adequate for testing of the outaged element as described in "a" through "e" by manual reclosing after the outage and before adjusting any generation. These requirements will also apply after any critical generator unit, transmission circuit, or transformer has already been lost, assuming that the area generation and power flows are adjusted between outages by use of Five-Minute Reserve.

a. A permanent three phase fault on any generator, transmission circuit, transformer or bus section, cleared in normal time, with due regard to reclosing facilities.

b. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple transmission circuit tower, cleared in normal time, with due regard to reclosing facilities.

c. A permanent phase to ground fault on any generator, transmission circuit, transformer,

or bus section with delayed clearing and with

due regard to reclosing facilities. This de-

layed clearing could be due to circuit breaker,

relay system or signal channel malfunction.

d.   Loss of any element without a fault.

e.   A permanent phase to ground fault on a circuit

breaker, cleared in normal time, and with due

regard to reclosing facilities.

3.2 Steady State Conditions

a.   Voltages, line and equipment loadings shall be

within normal limits for pre-disturbance con-

ditions.

b.   Voltages, line and equipment loadings shall be

be within applicable emergency limits for

the system load and generation conditions

that exist following the disturbance speci-

fied in 3.1.

4.   TRANSMISSION CAPABILITIES

Transfers of power from one area to another, as well as with-
in areas, should be considered in the design of inter-area trans-
mission and internal area facilities.

Operating capabilities shall be adhered to for normal trans-
fers and transfers during emergencies. These capabilities will
be based on the facilities in service at the time of the transfers.
In determining the emergency transfer capabilities, it is assumed
that a less conservative margin is justified.

Transmission transfer capabilities shall be determined under
the following conditions:

4.1 Normal Transfers

4.1.1 Stability Conditions

Stability of the interconnected power systems shall be maintained during and after the most severe of the conditions stated in a, b, c, d, and e below. Also, the system must be adequate for testing of the outaged element as described in "a" through "e" by manual reclosing after the outage and before adjusting any generation.

a. A permanent three phase fault on any generator, transmission circuit, transformer, or bus section, cleared in normal time, with due regard to reclosing facilities.

b. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple transmission circuit tower, cleared in normal time, with due regard to reclosing facilities.

c. A permanent phase to ground fault on any generator, transmission circuit, transformer, or bus section with delayed clearing and with due regard to reclosing facilities. This delayed clearing could be due to circuit breaker, relay system or signal channel malfunction.

d. Loss of any element without a fault.

e. A permanent phase to ground fault on a circuit breaker, cleared in normal time, and with due regard to reclosing facilities.

4.1.2 Steady State Conditions

a. For the facilities in service during the transfer, voltages, line and equipment loadings shall be within normal limits.

b. Voltages, line and equipment loadings shall be within applicable emergency limits for the system load and generation conditions that exist following the disturbance specified in 4.1.1.

4.2 Emergency Transfers

4.2.1 Stability Conditions

Stability of the interconnected systems shall be maintained during and after the most severe conditions in "a" and "b" below. System conditions may be adjusted before the outaged element as described in "a" and "b" below is tested.

a. A permanent three phase fault on any generator, transmission circuit, transformer, or bus section, cleared in normal time and with due regard to reclosing facilities.

b. Loss of any element without a fault.

4.2.2 Steady State Conditions

a. For the facilities in service during the transfer, voltages, line and equipment loadings shall be within applicable emergency limits.

b. Voltages, line and equipment loadings shall

be within applicable emergency limits

following the disturbance in 4.2.1.

5. <u>POSSIBLE BUT IMPROBABLE CONTINGENCIES</u>

Studies will be conducted to determine the effect of the follow-ing contingencies on system performance and plans will be developed to minimize the spread of any interruption that might result.

a. Loss of the entire capability of a generating station.

b. Loss of all lines emanating from a generating station, switching station or substation.

c. Loss of all transmission circuits on a common right-of-way.

d. Permanent three phase fault on any generator, transmission circuit, transformer, or bus section, with delayed clearing and with due regard to reclosing facilities. This delayed clearing could be due to circuit breaker, relay system or signal channel malfunction.

e. The sudden dropping of a large load or major load center.

f. The effect of severe power swings arising from disturbances outside the Council's interconnected systems.

APPENDIX - LIST OF DEFINITIONS

1. **AREA**

   An area is defined as either New Brunswick, New England, New York or Ontario.

2. **EMERGENCY**

   An emergency is assumed to exist in an area if firm load may have to be dropped because sufficient power is unavailable in that area. Emergency transfers are applicable under such conditions.

3. **APPLICABLE EMERGENCY LIMITS**

   These limits depend on the duration of the occurrence, and on the policy of the various member systems of NPCC regarding loss of life to equipment, voltage limitation, etc.

   Short time emergency limits are those which can be utilized for at least five minutes.

   The limiting condition for voltages should recognize that voltages at key locations should not drop below that required for suitable system stability performance, and should not adversely affect the operation of the interconnected systems.

   The limiting condition for equipment loadings should be such that cascading will not occur due to operation of protective devices on the failure of facilities.

4. **FIVE-MINUTE RESERVE**

   Five-Minute Reserve is that portion of unused generating capacity which is synchronized to the system, and is fully available within five minutes, plus that portion of capacity available in shut down generating units, in pumped hydro units and by curtailing interruptible loads which is fully available within five minutes.

5. "WITH DUE REGARD TO RECLOSING FACILITIES" is intended to mean that recognition will be given to the type of reclosing: i.e., manual or automatic, and the kind of protective schemes insofar as time is concerned.

6. ELEMENT

   An element is defined as a generator, transmission circuit, transformer, circuit breaker or bus section.

NORTHEAST POWER COORDINATING COUNCIL

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PROCEDURE

IN A

MAJOR EMERGENCY

Originally adopted by the
Members of the Northeast
Power Coordinating Council
based on recommendations
by the Operating Procedure
Coordinating Committee on
5/24/67. Revision adopted
by the Members of the Council
on March 27, 1972.

NORTHEAST POWER COORDINATING COUNCIL

PROCEDURE IN A MAJOR EMERGENCY

1. INTRODUCTION

This procedure outlines a plan of operations to be followed in the event of a major emergency such as unusually low frequency equipment overload, or low voltage, which might seriously affect the operation of the bulk power supply systems. The objectives of the plan are:

a. To restore the balance between load and generation in the shortest practical time.

b. To minimize the risk of damage to bulk power supply facilities.

c. To minimize the effect on customer service.

The plan of operation is intended to indicate the results that should be attained but does not indicate the method to be used to obtain these results. The basic system designs and the methods of control vary widely among the systems. The methods to be used in implementing this procedure in detail in each area will not necessarily be uniform but must be coordinated.

2. DEFINITIONS

Load Relief - Load reduction accomplished by reducing voltage or by load shedding or both.

Automatic Load Relief - Load reduction accomplished without manual intervention by reducing voltage or by load shedding or both.

Load Shedding - Disconnection of customer load.

Dispatchers - The terms dispatcher and system operator have the same meaning.

Area - As the situation requires, may mean a part of a system, or more than a single system.

3. PRINCIPLES

The plan of operation during an emergency derives from
the following basic principles:

a. Tie lines, including internal transmission circuits,
    should not be opened deliberately except to prevent
    sustained interruption to customers' service or to
    prevent damage either to such tie lines or to equip-
    ment due to overloads, extreme voltages, or extreme
    frequencies.

b. A sustained frequency excursion of $\pm$ .2 hertz is an
    indication of major load-generation unbalance. It is
    important for the area in trouble to provide load-
    generation balance at once to restore frequency so
    that any separated areas may be reparalleled as soon
    as possible.

c. Any general rule for balancing load and generation
    based on frequency alone risks undesirable overload-
    ing or tripping of tie lines or internal transmission
    circuits. If frequency is dropping rapidly, the risk
    from the application of underfrequency relays is pre-
    ferred to the risk of widespread shutdowns.

d. At some low frequency, the ability of generators to
    maintain output is endangered. Although some machines
    will operate safely below 58.5 hertz, for the sake of
    uniformity the value of 58.5 hertz has been selected for
    the last step in the following procedure. It is recognized,
    however, that some machines may be in danger above
    58.5 hertz. If a machine is tripped above 58.5 hertz,
    equivalent load relief must be provided.

e. Machines that are to be disconnected from the system,
    insofar as possible, should be isolated on local load to
    be available for resynchronization.

4.   REQUIREMENTS

In order to follow the recommended plan of operation effectively, each system should meet the following requirements:

a.   Accurate and reliable metering of tie line loadings and system frequency should be available at each dispatch center.

b.   Reliable and immediately available communication channels should exist between the dispatchers of adjacent power systems.

c.   Each dispatcher should know the permissible emergency loading of each of his tie lines and transmission circuits. The settings of the relays on the tie lines must exceed this value.

d.   Each system must provide a means to shed a minimum of 25% of its system load automatically to protect against low frequency conditions. This amount of automatic load shedding is designed to return frequency to at least 58.5 hertz in 10 seconds or less and to at least 59.5 hertz in 30 seconds or less, for a generation deficiency up to 25% of the load.

e.   Each system must provide a means to shed a minimum of 50% of its system load manually in 10 minutes or less to protect against low voltage and overload, as well as low frequency conditions. The automatic portion, if also controlled by manual means, may be included as part of the 50% manual portion.

f.   All automatic load frequency controls will be removed from service at 59.8 hertz on frequency decline and 60.2 hertz on frequency increase.

5. LOAD RELIEF PROCEDURE

5.1 Low Frequency Condition

1. Automatic

a. At a nominal trip point of 59.3 hertz all systems initiate shedding of 10% load.

b. At a nominal trip point of 58.8 hertz all systems initiate shedding of an additional 15% load.

c. By 58.3 hertz any member may automatically initiate shedding of additional load to meet his local conditions which may arise following separation from the system.

d. If the frequency drops to 57.5 hertz for 10 seconds or to 56.0 hertz for 0.35 seconds, any member may automatically initiate steps to protect generating equipment, including separation from the system with or without load. It is recognized, that in special cases unusual requirements may dictate higher settings for underfrequency relays to protect equipment from damage.

2. Manual

When the generation-deficient area is clearly identifiable, when the frequency decline is slow enough to permit communication among various system operators, and when adequate consideration can be given to the amount of assistance which can be delivered to the deficient area by all power systems, the following procedures will apply:

The deficient system will initiate immediate action to correct load-generation unbalance using procedures involving operating and emergency reserves including voltage reduction.

If the action taken by the deficient system is not sufficient, and frequency continues to decline, then automatic load shedding will occur as detailed above.

If at any time in the above procedure the decline in frequency is arrested and all operating and emergency

reserves have been actuated, the deficient system
shall then manually shed sufficient load to permit
resynchronizing the island.

At 58. 5 hertz, if frequency is still declining, all
systems shall shed up to 25% of load manually and
then take such steps as are necessary, including
isolating units with local load, to preserve genera-
tion and to minimize damage and service interrup-
tion.

When the generation-deficient area is not clearly identi-
fiable and when the frequency decline is so rapid as to
preclude analysis and communication among various
system operators, all systems will apply the above
procedure without regard to tie line loadings.

5.2   Transmission Overload Condition

1.   Establish communication with system operator of
system producing overload.

2.   All systems in a position to assist shall take any
available action to relieve the overloaded condition,
short of shedding load.

3.'   If the action in 2 above is insufficient, the system
causing the difficulty shall take all steps necessary
to relieve the overload promptly including the manual
shedding of load.

4.   If, after a reasonable time based on overload, im-
provement is not made, open those ties necessary
to prevent damage to equipment.

5. 3   Low Voltage Condition

1.   Establish communication with the system causing
the low voltage.

2.   All systems in a position to assist shall take any
available action to relieve the low voltage condition,
short of shedding load.

3.   If the action in 2 above is insufficient, the system
causing the difficulty shall take all steps necessary
to relieve the low voltage condition promptly, including
the manual shedding of load.

4. If, after a reasonable time based on voltage level, improvement is not made, separate the affected portion of the system to prevent damage to equipment.

6. <u>RESTORATION PROCEDURE</u>

In the event that an area becomes isolated and after the frequency decline has been arrested:

1. Restore frequency to 60 hertz.

2. Establish communication with system operators of adjacent systems.

3. Synchronize with adjacent systems.

4. Coordinate restoration of any load previously shed.

It is permissible to restore load concurrent with the performance of steps (2) and (3) provided frequency is maintained at 60 hertz, other system conditions permit, and synchronization with adjacent systems is not delayed as a result of such action.

NORTHEAST
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BULK POWER SYSTEM

PROTECTION PHILOSOPHY

Bulk Power System

Protection Philosophy

Prepared By

Northeast Power Coordinating Council

Task Force on System Protection

Adopted by the members of
the Northeast Power Coordinating
Council, August 31, 1970

1.0 PURPOSE

The purpose of this Protection Philosophy is to establish the relay protection objectives on the NPCC bulk power system. The bulk power system is defined as the interconnected three phase, alternating current electrical systems of NPCC members comprising generation and transmission facilities on which faults or disturbances can have a significant effect outside of the local area. These objectives shall apply to all relay protection systems specified for installation after the date of adoption of the philosophy.

Special conditions and considerations on some segments of the system may require the use of more demanding objectives.

It is recognized that there are existing portions of the system which do not meet the objectives as outlined herein. It will be the responsibility of individual members to assess the protection systems at these locations and make modifications which in their judgment are required to meet the general intent of this philosophy as outlined in Section 2.0.

2.0 GENERAL PROTECTIVE PHILOSOPHY

2.1 Protection Objectives

The design objectives of relay protection systems on the bulk power system are:

2.11 To minimize the effects of system disturbances.

2.12 To minimize possible damage to system equipment.

2.13 To insure to the maximum practical extent that no single contingency will totally disable the protection on any bulk power system element.

In general, this requires that protective relay systems have the ability to recognize and isolate all system faults rapidly and with a high degree of dependability and security. Reliable operation of protective relay systems on the bulk power system must be assured because a malfunction can have far-reaching effects, such as extensive service interruptions and/or damage to vital equipment. At minimum, this means that relay systems must satisfy the "NPCC Basic Criteria for Design and Operation of Interconnected Power Systems". However, consideration should be given to providing relay system designs which will permit the power system to meet more severe requirements than are contained in the above-mentioned criteria.

2.2 Dependability

Dependability is one of the two most important factors which must be considered in the design of relay protective systems. A dependable relay system design must include careful attention to the following:

2.21 To insure maximum dependability, all elements of the bulk power system must be protected by at least two protective systems, each of which is independently capable of detecting and isolating all faults without undue disturbance to the Bulk Power System consistent with basic NPCC criteria. Common components are to be avoided and areas of common exposure should be kept to a minimum, to reduce the possibility of any circumstance that may lead to the simultaneous failure of both systems. It is desirable to avoid the use of two identical systems in order to minimize the risk of simultaneous failure of both systems due to an obscure design or material weakness.

2.22 Relaying systems should be no more complex than is required for any given application.

2.23 The components used in protective relay systems should be of proven quality as demonstrated either by practical operational experience or by stringent tests under simulated operating conditions to insure that the dependability of the protective relay systems is not adversely affected by some device of unknown quality or capability.

Components should have both the ability to withstand the most severe short-time overloads to which they may be subjected, and a continuous thermal capability such that they will not impose restrictions on the operation of the power system.

The protective relay systems should be designed to minimize the possibility of component failure or relay malfunction due to transient conditions.

2.24 Monitoring of the protective system is required to provide information regarding its operating condition.

2.25 Breaker failure protection must be provided to trip all necessary local and remote breakers in the event that a breaker fails to clear a fault.

2.26 The relay system should be designed to minimize damage to relays and associated equipment in the event of a malfunction or failure of a component part.

2.3 Security

Ranking in importance with dependability is the ability of a protective system to be secure against undesired operations. In a highly complex bulk power system, an undesired breaker operation, occurring especially during a condition of system fault or other disturbance, may produce or initiate events of far-reaching consequences.

2.31 One of the primary requisites of a protective system is to isolate only the section necessary to remove any type of fault from the system. For faults outside of its intended zone of operation, every relay system must be designed to either not operate or operate selectively with other systems.

2.32 Protective systems should also be secure against any abnormal or unusual operational condition. They must be so designed that they will not operate for any system swing of less severity than that which would cause instability. Except in rare cases, protective relay settings should not be the load-limiting factor. In such cases, the load limits imposed by the relay setting must be well documented and become a system operating constraint.

2.33 The design should minimize the possibility of undesired operations caused by component failures or environmental conditions, such as vibration, shock, temperature, etc.

2.34 Circuitry and techniques should be employed which minimize the possibility of undesired operations due to personnel error.

2.4 Operating Time

Requirements of the bulk power system for high-speed clearing are particularly stringent. Normal practice should provide for clearing all faults in the shortest possible time with due regard to selectivity, dependability and security. In those cases where there is consideration of a possible increase of clearing time to gain other advantages, careful analysis must be given to the following:

2.41 System stability and any decrease in stability margins which might result from longer clearing times.

2.42 Possible damage to equipment and the effect of time on the extent of damage which might be expected if faults are allowed to persist for a longer time than minimum.

2.43 Possible hazard to personnel.

2.44 Effect of disturbances on service to customers in the area and the consequences which may result from voltage fluctuations during such disturbances.

2.5 Maintenance

The design of the protective relay system should facilitate periodic testing and maintenance. Test devices or switches should be used to eliminate the necessity to remove or disconnect wires during testing.

Equipment should be located physically so as to be easily accessible.

2.6 Coordination of System Planning and Relay Protection

Close cooperation should be maintained between the respective System Planning, Operating, and Protection groups to insure that modifications or additions to the power system or its relaying will result in facilities that can be adequately protected and reliably and safely operated.

3.0 GENERAL CONSIDERATIONS FOR ALL APPLICATIONS

3.1 Instrument Transformers and Potential Devices

3.11 Current Transformers - Each current transformer associated with relaying must have adequate characteristics for its intended function. In particular, the following requirements apply:

3.111 The long-time thermal capability on the highest ratio tap should be at least equal to the long-time thermal capability of the equipment with which the current transformer is associated.

3.112 The output of each current transformer must remain within acceptable limits under all anticipated fault currents and connected burdens to insure correct operation of the protective relay system.

3.113 The short-time thermal and mechanical capabilities on the operating tap must be adequate to prevent damage under maximum fault conditions or emergency system loading conditions.

3.114   In each independent relaying system,
        separate current transformer secondary
        windings must be used.

3.115   The current transformer or its secondary
        windings must be located so that
        adjacent relay protective zones overlap.

3.116   Current transformer secondary systems
        (paralleled current transformers,
        differential systems, etc.) must be
        grounded at only a single point.

3.117   Care should be taken in specifying the
        size and type of current transformer
        secondary leads to assist in keeping
        the current transformer burden within
        design limits and to provide mechanical
        strength.

3.12 Potential Transformers and Potential Devices

3.121   Potential transformers and potential
        devices must have adequate characteristics
        and volt-ampere capacity to supply the
        connected burden and maintain their
        required accuracy over the specified
        primary voltage range.

3.122   Two relay systems protecting the same
        area must not rely on a common source
        of potential. The two systems may use
        separate secondary windings on one
        transformer or device, provided each
        secondary winding has sufficient capacity
        to permit fuse protection of the circuit.

3.123   Where fuse ratings of less than 20 amperes
        are used, special attention should be
        given to the physical properties of the
        fuse.

3.124   Potential transformer secondaries should
        be grounded at only one point.

3.2 Batteries and Direct Current (DC) Supply

3.21 It is essential that the DC supply associated with the
      power system protection have an extremely high degree
      of reliability.

3.22 Two batteries each with its own charger must be
      provided at each location. The two relaying
      systems protecting the same area must be supplied
      from separate batteries.

3.23 Each battery should have sufficient capacity to permit operation of the station in the event of loss of its battery charger or battery charger supply source for the period of time necessary to switch the load to the other battery or re-establish the supply source. Each charger should be of sufficient capacity to supply the total DC load of the station.

A switching arrangement should be provided to connect the total load to either battery without creating areas where, prior to failure of either a battery or a charger, a single contingency can disable both DC supplies.

3.24 Batteries and chargers and all associated circuits must be protected against short circuits, and all protective devices should be coordinated to minimize the effect of any disturbance.

3.25 The circuitry between the battery and its first protecting device should possess the highest possible degree of reliability.

3.26 The regulation of the DC voltage should be such that voltage within acceptable limits will be supplied to all devices under all DC loading conditions.

3.27 Abnormal DC voltage levels, both high and low, should be monitored to detect charger and battery troubles. Other abnormal conditions, such as loss of AC to battery chargers, charger failure, and DC system grounds should also be monitored.

3.28 Careful attention should be given to the design of the DC system to minimize voltage transients.

3.3 Circuit Breakers

The application of circuit breakers should conform to appropriate standards as published by the American National Standards Institute.

Circuit breaker auxiliary switches used in protective relay circuits should be of a highly reliable type with a positive make-break action and good contact wipe.

Two trip coils must be provided for each operating mechanism and so arranged that failure of one coil will not damage or impair the operation of the other coil.

3.4 Control Wiring

Control wiring and all auxiliary control devices should be of such quality as to assure high reliability with due consideration given for published codes and standards, fire hazards, current-carrying capacity, voltage drop, insulation level, mechanical strength, shielding, grounding and environment.

3.5 Physical Separation

Physical separation should be maintained between any two relaying systems which protect the same area in order to minimize the risk of both sets being simultaneously disabled by fire or accidents.

3.6 Communication Channels

Where communication channels are required to obtain adequate relaying, the communication facilities should be of such overall quality as to reflect the same degree of reliability as the relay system.

Where redundant communication channels are required, these channels should be separated physically and designed to minimize the risk of simultaneous failures by avoiding mutual-use components.

3.7 Environment

Means should be employed to maintain environmental conditions that are favorable to the continued correct performance of protective relays.

4.0 TRANSMISSION LINE PROTECTION

Each of the two independent relay systems must recognize and initiate action to clear any line fault without undue system disturbance. One of the relay systems should operate fast enough for any line fault so that if ultimate clearing must be accomplished by a breaker failure scheme, a widespread system disturbance will not result. A protective system, which can operate for faults beyond the area it is designed to protect, should be selective in time with breaker failure clearing of the area it is overreaching, except in those cases where lack of selectivity can be tolerated.

Relay systems associated with transmission facilities must be designed not to operate due to system swings which are less severe than those which would result in instability. Where stability is not a consideration, the relay system should not limit the load-carrying ability of a line except in unusual cases; and under such circumstances, the conditions must be well documented.

Where relaying systems require communication facilities in order to perform their protective function, the protective systems must be so designed that a loss or misoperation of any one communication facility will not allow incorrect tripping of more than one line for an external fault. The design must also be such that if two relay systems protecting the same line use communication facilities, the loss of any one communication facility or power supply will not impair the operation of both relay systems.

5.0 TRANSMISSION STATION PROTECTION

Each area in a station must be protected by two independent relay systems. In areas not protected by line relaying, at least one of the two systems should be a differential type.

One of the relay systems should operate fast enough for any station fault so that if ultimate clearing is accomplished by a breaker failure system, a widespread disturbance will not result. The relay systems should operate properly for the anticipated range of currents and, if practical, to the momentary rating for which the buses are constructed.

All relay systems must be designed so they will not operate for load current or system swings which are less severe than those which would result in instability.

Due consideration should be given to the station ground grids, control cables, etc., to minimize the risk of false operation of protective relay systems which might result from fault current and/or transient voltages in the station.

5.1 Breaker Failure Protection

Breaker backup relay systems must be installed to trip local and remote breakers as required to protect the system if any breaker fails to interrupt. One set of relays protecting each individual area must also initiate the breaker failure protection. Fault current detectors must be used to determine if a breaker has failed to interrupt. In addition, auxiliary switches may be necessary for high-speed detection of a failed breaker where the distribution of fault current may be such that fault detectors operate sequentially. Examples of this can be found with breaker-and-one-half and ring-bus arrangements. Auxiliary switches may also be required, in instances where the fault currents are not large enough to operate the fault detectors.

6.0 GENERATOR PROTECTION

Generator faults severe enough to disturb the bulk power system must be detected by more than one protective relay system.

In addition, generators should be protected to keep damage to the equipment and outage time to a minimum.

In view of the special consideration of generator unit protection, the following items are listed as electrical conditions which should be detected by the protective relays:

1. Field ground
2. Loss of excitation
3. Faults in the generator or generator leads
4. Generator out of step with the rest of the system
5. Faults in the unit transformer
6. Unbalanced phase currents
7. Faults in unit-connected station service transformer
8. Over-excitation

It is recognized that the overall protection of a generator must also involve non-electrical considerations. These have not been included as a part of this philosophy.

The apparatus should be protected when the generator is starting up or shutting down as well as running at normal speed; this may require additional relays as the normal relays may not function satisfactorily at low frequencies.

A generator should not be tripped for a system swing condition except when that particular generator is out of step with the remainder of the system. This does not apply to relay systems designed to trip the generator as part of an overall plan to maintain stability of the power system.

No.   E2
Date   February 10, 1975

System Planning Division

Guides for Planning Area and Regional Supply Facilities

1. Introduction

    System Planning Division Procedure No. El "Guides for Planning
the Main Trunk Transmission System" specifies the reliability require-
ments for design of the power system. While those criteria
apply mainly to the bulk power system where contingencies are
more likely to cause loss of a major portion of the East System
or jeopardize the interconnected system, they also apply to
other parts of the power system where local instability from
a fault could cascade into the bulk power system. Studies to
check the adequacy of all parts of the system to meet those
criteria are normally carried out by those who plan the bulk-
power system.

    In addition to designing the system as a whole for adequate
stability and steady-state operation, it is necessary to design
each part of the system for adequate continuity or availability
of supply to individual large customers and to transformer stations
supplying the distribution system. Criteria for availability are
therefore required, particularly for the parts of the system
known as Area and Regional Supply Facilities. Such criteria are
contained in this Procedure E2.

    It is also necessary to provide facilities for maintaining
adequate normal and emergency voltages throughout the system.
Voltage control is achieved mainly by installation of
reactive power sources throughout the system, from genera-
tors to distribution capacitors. Voltage criteria will
be covered by a separate procedure.

    This Procedure E2 is not intended as a set of rigid rules,
but rather as a guide towards establishing the minimum availabi-
lity criteria for the Area and Regional Supply system. Parts
of the system may be designed for lower availability, but this
should only be done where the stage is temporary, where the
reliability requirements of the load are low, or where the cost
of the recommended reliability is unjustifiably high. Occasionally
a higher availability may be justified, where the load is un-
usually sensitive or the cost of improvement is low.

    Copies of this Procedure are being sent to the Power System
Operations Division, with a note emphasizing that it is being used
as a guide only, and hence will not be rigidly applied.

Because this Procedure is based primarily on the accumulated experience of the members of System Planning Division, it will be revised as considered necessary. Section Heads and Planning Engineers are asked to use this procedure now on a trial basis and to report any comments or suggestions for change to their Department Head.

2. The Area and Regional Supply System

This comprises all 230 kV and 115 kV circuits supplying step-down transformer stations from 230 kV or 115 kV to 44, 27.6 or 13.8 kV (called LV in the following), the step-down stations themselves, and the   ·   500-115, or 230-115 kV autotransformers and associated switching used for area supply. The high-voltage switching at major stations must be considered not only for its effect on area supply, but also for its effect on system stability.

3. Normal Operation

Normal operation is the condition under which all lines, trans-formation and switching in the location being studied are in-service. Under these conditions all facilities are to be loaded within their established normal capabilities, and all voltages are to be within their normal range for any condition of load or generation which could reasonably be expected to occur at any time of the year.

4. Emergency Operation

Emergency operation is the condition under which one or more elements of the system are out of service for routine maintenance, or for repair because of a failure. A number of common emergency conditions are listed in Table I. The operating conditions applying during the emergency are determined by the availability level assigned for a particular emergency and a particular size of load. These availability levels are defined in Section 6 below.

In all availability levels except C, it is permissible for the load to be interrupted, but the load must be restored to service within the specified period, depending on the availability level.

At all times during the emergency while load is being supplied, all facilities are to be loaded within their applicable emergency capabilities. This may be either short-term or long-term emergency capability as conditions dictate.

5. Load Level

        The availability level required depends on the size of the
load. For purposes of Table I, the load level is the peak load
in Megawatts for the most critical month for the station or
group of stations being studied, for a time about 2 to 5 years
hence, depending on the lead-time for the new facilities.
It is the load which would be interrupted by the
occurrence of the contingency listed. Where "Interruptible"
load is supplied from a station, the level of availability
required should be discussed with Customer Service Division.

6. Availability Levels

    C   Continuous supply. This is the highest level.
           There should be no interruption in supply as a
           result of the occurrence of the contingency.
           This level is designated C in Table I.

           The voltage may collapse for a few cycles while
           a fault is being cleared but it must rise
           immediately after fault clearance, and must be
           restorable to an acceptable emergency level by
           automatic action such as on-load tap changers.
           Transfer of such load to another source is
           permissible to relieve overload, but the
           transfer must be done without interrupting the
           load.

    RR   Restorable Rapidly. An interruption of 2
           seconds is permissible at the time of a
           contingency or at the later time of load trans-
           fer. Restoration within 2 seconds must be
           accomplished automatically by operation of LV
           breakers without operator intervention.

    RS   Restorable by Switching. Load may be interr-
           upted at the time of the contingency, but it
           must be restorable within one-half hour, for example
           by the action of a control-room operator using
           remote or supervisory control, or by use of
           automatically operated switching at the affected
           station.

    R2   Restorable by Manual Switching. Load may be
           interrupted at the time of the contingency, but
           it must be restorable within 2 hours. It is assumed
           there will be switches, quick-openers or other
           devices available, which can be operated by a
           travelling operator or maintenance man to restore
           service. Means of quickly transferring metering, and
           relaying will also be required.

R8   Restorable by Maintenance. Load may be interr-
upted at the time of the contingency, and
restoration must be within 8 hours. Restoration
is assumed to be the result of repair work
or temporary connections which can be made by a
maintenance crew. This may comprise such line
work as replacement of a pole, crossarm, or in-
sulators, repair of a broken conductor, by-
passing a defective switch, or such station work
as repair or replacement of a defective low-
voltage breaker, connecting of an on-site spare
transformer (including metering, relaying, and
service supply). Station design must be suitable for
transformer connection to be accomplished within
8 hours.

X   There is no fixed standard of availability against
contingencies marked X. These are treated as
"Possible but Improbable Contingencies". Each
case must be considered separately, taking into
account the probability of occurrence, length of
repair time, extent of hardship caused, and
cost of providing availability against the con-
tingency. In any specific case the availability
will be at a level no higher than R8, and may
be as low as to permit the outage to extend for
several days.

7.   Requirements for Transferring Load

     The action to restore supply may be taken either at the
location where the fault occurred, thus restoring supply
along the normal supply path, or at a remote location to
transfer the load to another source. If load is trans-
ferred, provision must also be made to transfer it back to
the normal supply at a convenient time with minimum interr-
uption.

     In the case of transformers and some cables, which have
a high short-term overload capability, advantage may be taken
of this capacity, provided excess load can be transferred
off within the time limit set by the short-term capability.

8. Possible but Improbable Contingencies

No standards are set for availability against more severe contingencies than those listed in Table I because of their low probability of occurrence and the generally very high cost of reliability measures. However, consideration should be given to the effect of these contingencies on specific important loads, and the availability against them should be improved wherever this can be done at reasonable cost.

Some catastrophic contingencies for which there is no minimum standard are:

- Loss of several towers due to windstorm or vehicle impact.

- Simultaneous or overlapping outage of two independent elements, such as outage of a transformer and the line supplying a second transformer at the same station.

- Fire or explosion following a fault.

- Loss of all circuits on the same right of way.

- Loss of a complete station.

Another group of contingencies which can occur, but which are only affected to a limited extent by planning decisions are listed below.

- Errors in design, construction, or operation.

- Failure or misoperation of relaying.

- Failure of supervisory control.

- Faults in station service system.

One type of possible but improbable contingency which will need more consideration in future is the catastrophic outage of several circuits on one right of way. It is likely that in the medium term future there will be narrow rights of way containing heavily-loaded multi-circuit tower lines

with close spacing between lines and shared use of the right
of way. In such cases, there is risk of an extended outage
to one or more towers of one or more lines due to causes such
as: -   Tornadoes

-     impact by aircraft

-     gas-line explosion

-     relocations for highway modifications

-     footing damage due to flooding or
      land slippage.

In the past, it was possible to provide a temporary woodpole
bypass circuit on short notice, but such will not be possible
on a crowded right of way. Therefore, consideration will
have to be given to provision of back-up circuits from a
different direction so that part of the load can be restored
while repair to the damaged section is carried out. The
criteria of Table I require provision of backup to large loads for
loss of two circuits, but this backup need not be from a different
direction, and can, in fact be from two other circuits of
the same multicircuit line.

H.P. Smith
Director of System Planning

TABLE I

AREA AND REGIONAL SUPPLY
MINIMUM AVAILABILITY LEVELS

TYPE OF FAULT OR OUTAGE	Load Level of Station or Group Affected By Fault Or Outage(Megawatts)						
	1 To 15	16 To 40	41 To 75	76 To 150	151 To 250	251 To 500	501 And MORE
Transformer	R8	R2*	RS**	RS	RR	C	C
Overhead Circuit	R8	R8	R8	RS	RR	C	C
Cable Circuit	X	X	R8	RS	RR	C	C
Bus	R8	R2*	R2	R2	R2	C	C
Breaker	R8	R8	R2	R2	R2	R2	R2
Maintain an Element	Same as For Fault						
Two Transformers	X	X	X	X	X	X	X
Double-Circuit Line (Non-Catastrophic)	R8	R8	R8	R8	R8	RS	C
" " " (Catastrophic)	X	X	X	X	X	RS	C
2 ccts of Multicircuit Line	R8	R8	R8	R8	R8	RS	C
Multicircuit Line (Catastrohpic)	X	X	X	X	X	X	X
Two Cables in Same Trench	X	X	X	X	RS	RS	RS
Two Cables Different Trenches	X	X	X	X	X	X	RS
Two Breakers	R8	R8	R8	R8	R8	R8	R2

```
                                    * Up to 15 MW can be R8
                                   **  "   "  40  "   "   "   R2
```

C - Continuous
RR - Restorable Rapidly (LV switching in 2 sec)
RS - Restorable by Switching (30 Min)
R2 - Restorable in 2 Hours by Travelling Operator
R8 - Restorable in 8 Hours by Maintenance Crews
X - No Special Provision

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High Voltage Stations and Transmission Lines
Number of Breakers Tripped to Clear Faults

1. Introduction

As our high voltage stations and transmission
systems are expanded, more transformers are being
connected directly to station buses or transmission
lines, and more breakers are required to trip to clear
all infeeds to a fault. As a result, relaying systems
are becoming more complex to provide adequate first
line protection. Also with these increasing complex-
ities, the chance of failure to clear all infeeds
rapidly is increasing, necessitating further complex-
ities for backup protection.

It is not possible to calculate mathematically
the optimum balance of complexity, reliability and cost
in specifying station diagrams. Therefore a review of
existing practices within Ontario Hydro has been made,
and, based on it, this Procedure has been prepared as
a guide to show the maximum complexity which should
normally be permitted in design of station diagrams or
switching connections for transformers or circuits.

Because it lacks a scientific basis, the Procedure
is not intended as a set of rigid rules, but only as a
guide toward establishing the maximum complexity which
should normally be specified. Less complex diagrams
(usually at higher cost) would be specified in cases
where serious relaying difficulties would be encountered
with the arrangements proposed in the Procedure, where
the size or importance of the load justifies higher
security, or where the additional cost is low. Diagrams
more complex than the desired maximum should only be
specified where the stage is temporary, where the rel-
iability requirements are low, or where the cost of
lower complexity is unjustifiably high; and in such cases,
only where relaying adequate to the reliability require-
ments is feasible.

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Copies of this Procedure are being sent to the Power System Operations Division, with a note emphasizing that it is being used as a guide only, and hence will not be rigidly applied.

Because this Procedure is based primarily on the accumulated experience of the members of System Planning Division, it will be revised as considered necessary. Comments and proposals for changes will be welcomed from Planning Engineers and Section Heads, and should be addressed to the Department Heads.

2. General

2.1 This Procedure applies to 500 kV, 230 kV, and 115 kV ring bus, breaker-and-one-half, and breaker-and-one-third diagrams at switching and transformer stations; and to transformer switching at 50 kV and lower voltages at transformer stations.

2.2 It shows the maximum complexity of switching diagrams which should be provided under average planning conditions. The complexity is stated in terms of the maximum number of autotransformers or stepdown transformers which may be connected to a bus or circuit, and the maximum permissible number of high-voltage breakers which may be required to trip at any station for a fault on any element.

2.3 It does not attempt to specify the degree of complexity which should be permitted in the relaying. Relaying considerations must be investigated in each case after a preliminary selection of the switching diagram has been made.

2.4 It is not a set of rigid rules, but is for reference purposes only. The planner must consider each case individually. Diagrams with a lower level of complexity (generally resulting in higher cost and higher reliability) should be provided wherever relaying considerations dictate or wherever there is justification because of the size and importance of the load. Diagrams with a higher level of complexity should only be used under special circumstances, such as for short-term requirements, or for loads with low reliability requirements, or where the cost of normal complexity is unjustifiably high.

2.5 The Procedure assumes the use of the following types
     of transformation:

Autotransformers - 1∅ or 3∅ with
   (autos)   High Voltage - 500 or 230 kV
                      Low Voltage - 230 or 115 kV
                      Tertiary Voltage - 27.6 kV or 13.8 kV
                      Tertiary to be switched by not more
                      than 2 breakers.

Stepdown Transformers - High Voltage - 500, 230 or
                        115 kV
                        Low Voltage - 44, 27.6 or 13.8 kV
                        One or two low voltage windings.
                        Each 44 or 27.6 kV winding
                        switched by 1 breaker.
                        Each 13.8 kV winding switched by
                        1 or 2 breakers.

These cover the range of types of transformation at
present in common use, but are not intended to be
limiting.

2.6 Information is given in tabulated form in Sections 3
     and 4. Figures 1-16 illustrate the application of
     the guide to typical system arrangements.

3. Specific Guidelines for 230 and 115 kV Stations

3.1 Buses in Major Stations

     The maximum number of circuit breakers which
may be connected to a HV (230 kV) or LV (115 kV)
bus depends on the amount of equipment connected
to the bus, as follows:

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Equipment Connected to Bus	No. of Breakers	Figures
No circuit or transformation	6	1
1 auto	5	2
1 or 2 stepdowns	5	1
1 auto plus 1 or 2 stepdowns	4	2
Circuits up to 5 miles long		
Radial circuit with 1 auto	4	·10
Radial circuit with 1 or 2 stepdowns	4	11
Radial circuit with 2 autos	3	
Radial circuit with 3 or 4 stepdowns	3	12
Radial circuit with 1 auto plus 1 or 2 stepdowns	3	
Trunk circuit with no transformation	3	5

        Studies are being made of connecting a capacitor
or a reactor directly to the 230 kV bus through a
single radial breaker. Because tripping is not
necessary for short-circuit interruption, such a
breaker may be in addition to the breakers in the
above list.

3.2 Simple Ring-Bus Stations

        The initial stage of a major station may be
specified as a simple ring of up to eight breakers,
with the maximum number of breakers in the ring
depending on the number of circuits terminating at
the station, as follows:

Equipment Switched at Station	Breakers in Ring	Figure
4 circuits or fewer plus transformation	8	3
5 circuits plus transformation	7	
6 circuits	6	4

The following equipment may be connected to any switching position or to any circuit switched at the station.

- 1 auto
- 2 autos
- 1 auto plus 1 stepdown (Figure 3)
- 1 stepdown
- 2 stepdowns
- 3 stepdowns

3.3   Station Connections for Trunk Circuits

Trunk circuits are those which are switched at both ends (or all three ends) at main terminal stations. Trunk circuits are usually part of the bulk power network and may be required to carry power flow in either direction.

Transformation may be connected to trunk circuits, as listed in 3.3.1 and 3.3.2. This transformation may be connected at more than one station. The stations do not all have to be adjacent to the main route of the trunk circuit, taps several miles long being permitted.

3.3.1   Two-ended Trunk Circuit

Description of Circuit	Breakers at Each Terminal	Figure
Up to 5 miles long, no transformation connected	3	5
Longer than 5 miles No transformation connected	2	6
1 auto + 2 stepdowns	2	7
4 stepdowns	2	8

3.3.2   Three-ended Trunk Circuits

- each end to be switched by 2 breakers (Figure 9)

- Transformation connected to the circuit is limited to 2 stepdowns (Figure 9)

3.4   Station Connections for Radial Circuits

Radial circuits are those which are connected to a main terminal station at one end only and carry power from that point to one or more transformer stations supplying area load. Normally there will be two or more radial circuits supplying these transformer stations, with these circuits connected to the same terminal station and paralleled through low voltage switching at the transformer stations. (This usage of "radial" differs from the distribution usage which implies one circuit only supplying a load).

In some cases, radial circuits will have normally open switches at their ends (as shown in Figures 10-14) through which connections can be made to 230 kV circuits from another terminal station. It is intended that these switches will only be used to transfer radial load to another terminal station, and that when the switches are closed another open point between terminals will be established. If it were intended that the switches be normally closed to maintain a parallel between terminal stations, it would be necessary to treat the circuits as trunk circuits.

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- A radial circuit may be used to supply up to
  3 autos, or 6 stepdowns or an equivalent combination

- The transformation may be connected to the circuit
  at more than one station. The stations do not all
  have to be adjacent to the main route of the line,
  taps several miles long being permitted.

- The numbers of breakers used to switch the circuit
  at the terminal station are to be limited to the
  following:

Equipment Connected to Circuit	Breakers at Terminal Stn.	Figure
Radial Circuits up to 5 Miles Long		
1 auto	4	10
1 or 2 stepdowns	4	11
1 auto plus 1 or 2 stepdowns	3	
3 or 4 stepdowns	3	12
2 autos	3	
Radial Circuits Longer than 5 Miles		
1 or 2 autos	2	
1 or 2 stepdowns	2	
1 auto plus 1 or 2 stepdowns	2	
3 or 4 stepdowns	2	
1 auto plus 3 or 4 stepdowns	2	
2 autos plus 1 or 2 stepdowns	2	13
3 autos (at one or two stations)	2	
5 or 6 stepdowns	2	14

3.5 Autotransformers

Autotransformers have two major terminals
(HV and LV). One of these terminals (either HV
or LV) should be connected to a position switched
by 2 breakers which has no other circuits or equip-
ment connected. The other terminal may be connected
as permitted in the preceding subsections of
Section 3. However, other alternatives are permitted
which achieve essentially the same result.

3.6 Generating Stations

The high-voltage switching at generating stations
should normally be specified as outlined in this
Procedure, except that generator series synchronizing
breakers should be considered on their own merits.

3.7 System Diagrams

Figures 1 to 14 illustrate some of the arrangements
described in Section 3. They are not intended to
illustrate all possible combinations. For example,
Figure 8 shows four transformers connected to a trunk
line. These transformers may be at 4 different stations
along the line, as shown, or all at one station, or
some other combination.

The permissible numbers of breakers listed in
Section 3 are in terms of one element. However, for the
Figures, it is clearer to illustrate the principles as
they apply to Jones type two-line supply. The Figures
assumed the use of double-circuit lines, but the guide is
intended to apply to single-circuit, double-circuit,
multi-circuit lines or underground cables.

4. Specific Guidelines for 500 kV Stations

It is intended that eventually the guidelines given
in Section 3 for 230 kV stations will also be applied to
500 kV stations. However, in the initial stages of the
500 kV system it is proposed to adopt guidelines which will
result in reduced complexity.

The guidelines in this section will not apply to certain
500 kV stations now being designed where in-service dates
are critical.

4.1 Buses at Major Stations

The maximum number of circuit breakers which may be connected to a HV (500 kV) or LV (230 kV or 115 kV) bus depends on the amount of equipment connected to the bus, as follows:

Equipment Connected to Bus	No. of Breakers	Figure
No circuit or transformation	6	
1 auto	5	15
1 stepdown	5	
1 auto plus 1 stepdown	4	15
2 autos	3	
2 stepdowns	4	

4.2 Simple Ring-Bus Stations

The maximum number of breakers in the ring is normally 6, but 8 may be considered for special applications. Where 8 breaker rings are proposed, studies will be carried out to ensure that the system can withstand normal contingencies with a breaker out of service for maintenance.

4.3 Station Connections for 500 kV Trunk Circuits

Trunk circuits are to be two-ended and switched by not more than two high-voltage breakers at each end (Figure 6). Transformation will be tapped off the circuit only in special cases.

High voltage breakers may be omitted where a line is terminated by one or two autotransformers as shown in Figure 16. The low-voltage switching in this case must be not more than two breakers per autotransformer.

4.4 Radial 500 kV Circuits

Since 500 kV and 230 kV circuits will be operated in parallel in the early stages, there will not be any 500 kV radial circuits. Therefore no guidelines are included.

4.5 500 kV Autotransformers

If the high voltage autotransformer connection is to a bus (as in Section 4.1) or to a line (as shown in Figure 16), the low-voltage connection should be switched by not more than two breakers. If the high-voltage connection is switched by only two breakers, the low-voltage connection may be switched by up to 5 breakers, as listed in Section 4.1.

4.6 Generating Stations

The high-voltage switching at generating stations should normally be specified as outlined in this Procedure, except that generator series synchronizing breakers should be considered on their merits.

5. Analysis of System Connections

After diagrams for switching at one or more stations have been developed, a sketch should be made of the connections at the station and at adjacent stations to analyze the effect of various failures and maintenance outages on the continuity of supply to the stations in the area. For example, the following contingencies should be examined:

- any breaker isolated for maintenance

- fault on any element, including breaker

- fault on any element with backup clearing because of a stuck breaker

- fault on any element while any breaker is out for maintenance

- overlapping or simultaneous outage of any two circuits

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For example, in Figure 2, a fault on autotransformer A with failure to clear by a high-voltage bus tie breaker will cause loss of a second autotransformer. Or in Figure 2, a fault on breaker 1 while breaker 2 is out for maintenance will cause loss of two autotransformers. In Figure 8, a double-circuit fault will cause loss of supply to 4 Jones stations. In each case where a multiple effect occurs, it will be necessary to make reference to the "Guides for Planning the Bulk Power Transmission System" or the "Guides for Planning Area and Regional Supply Facilities" to determine whether loss of load is permissible or not.

H.P. Smith

H.P. Smith
Director of System Planning

FSB/sgf

cc. - All Bookholders
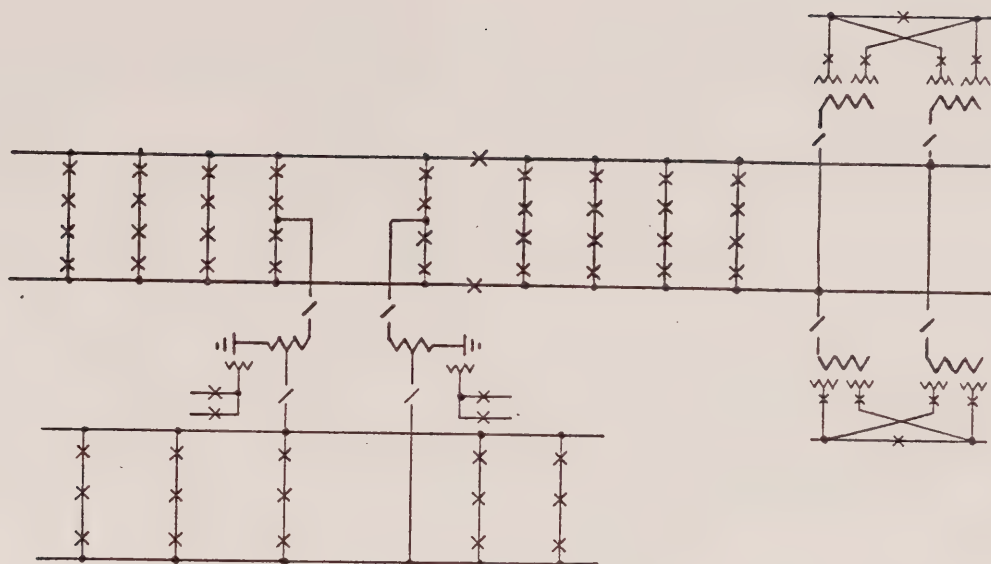
MAIN BUS
    WITH 5 & 6 BREAKERS

FIGURE · 1
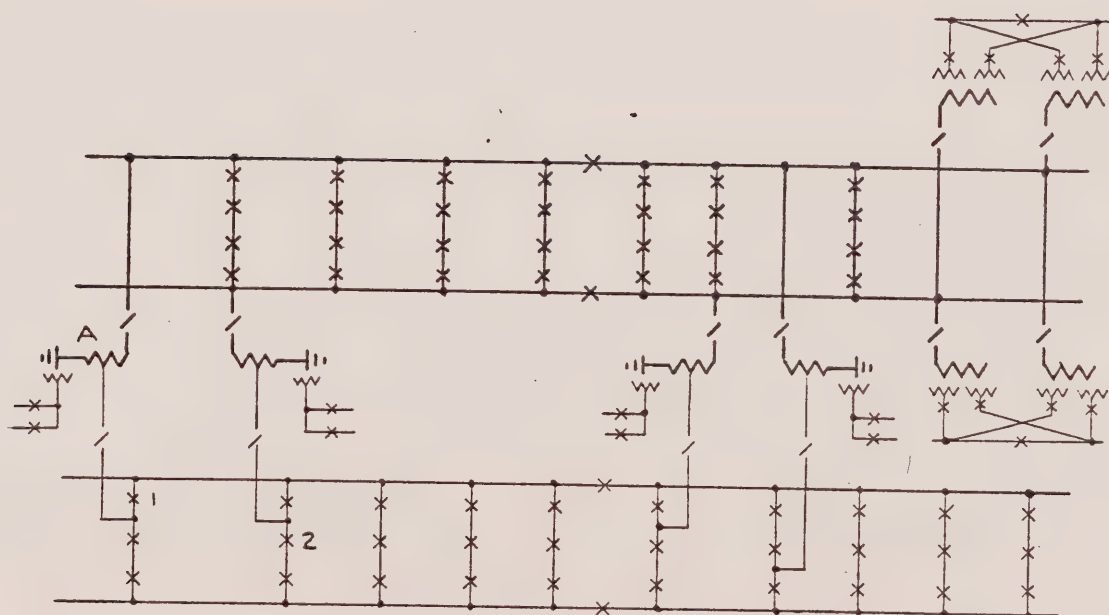
MAIN BUS
    WITH 4 & 5 BREAKERS

FIGURE · 2

UMBER OF BREAKERS TRIPPED TO CLEAR FAULTS
FIGURE 1 & 2.
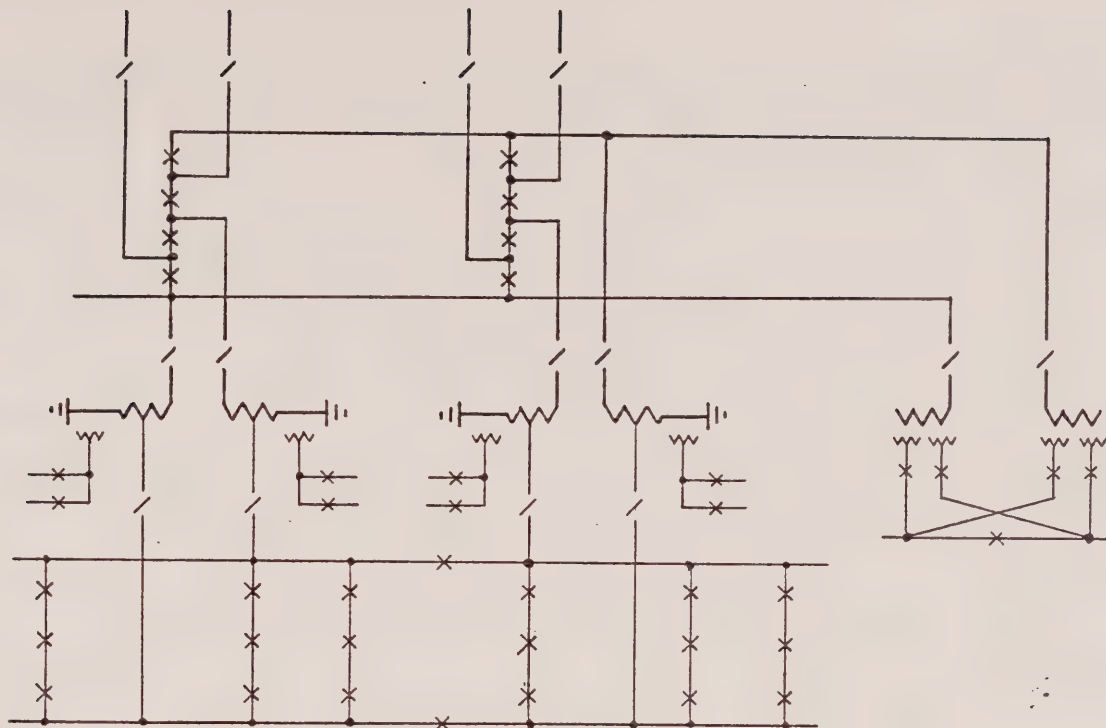
RING BUS (8 BREAKERS)   FIGURE · 3
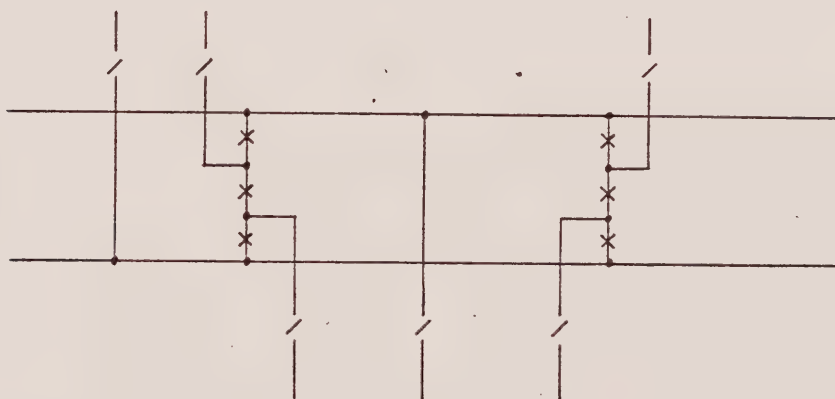
RING BUS (6 BREAKERS)   FIGURE · 4

NUMBER OF BREAKERS TRIPPED TO CLEAR FAULTS
FIGURE 3 & 4
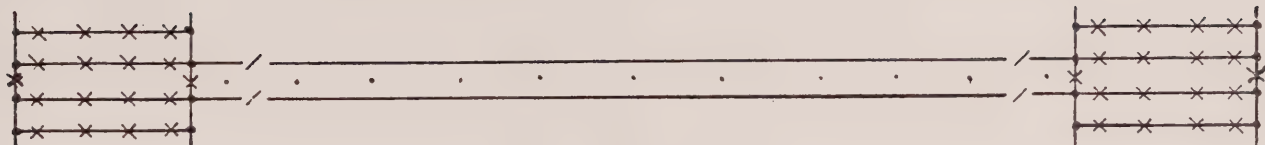
TRUNK LINES

TWO-ENDED SHORT LINES
(NO TRANSFORMATION)

FIGURE·5

TRUNK LINES

TWO-ENDED LONG LINES
(NO TRANSFORMATION)

FIGURE·6
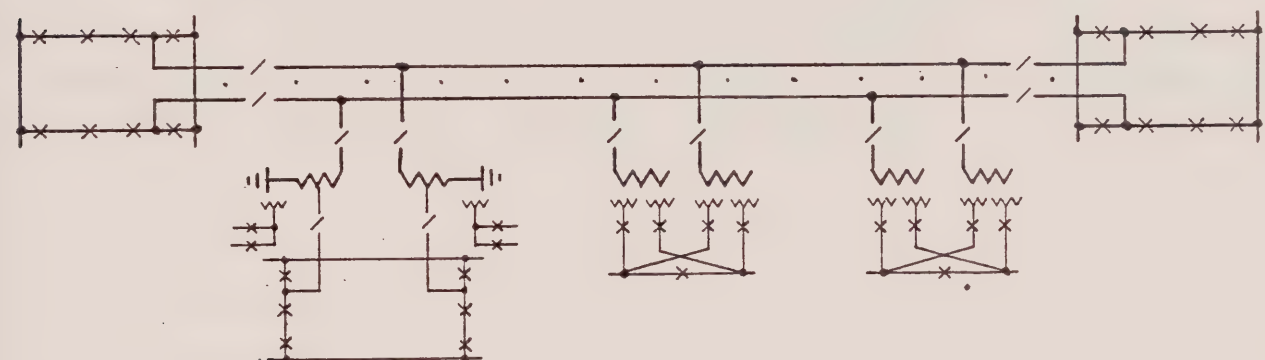
TRUNK LINES

LINE WITH 1 AUTO & 2 STEPDOWNS

FIGURE·7
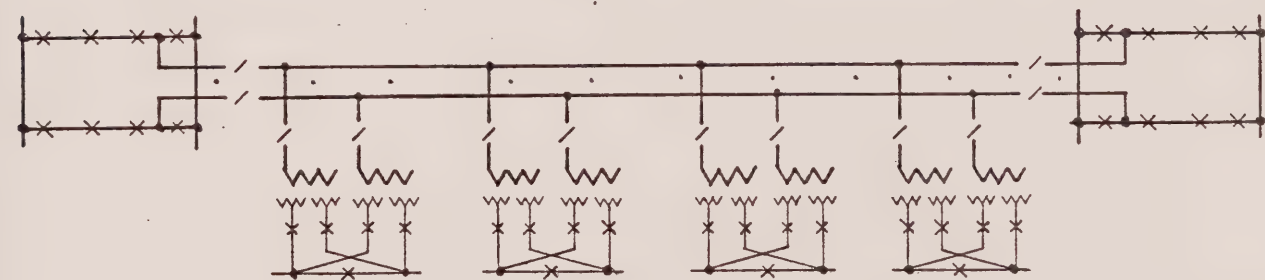
TRUNK LINES

LINE WITH 4 STEPDOWNS

FIGURE·8

NUMBER OF BREAKERS TRIPPED TO CLEAR FAULTS

FIGURE 5, 6, 7 & 8
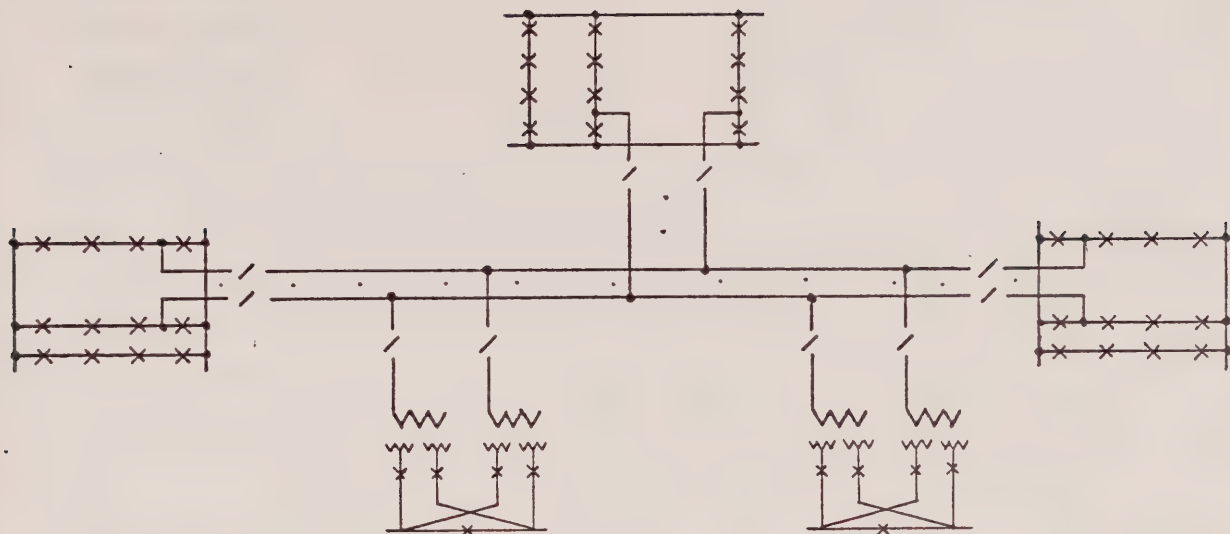
TRUNK LINES
THREE-ENDED LINE WITH 2 STEPDOWNS
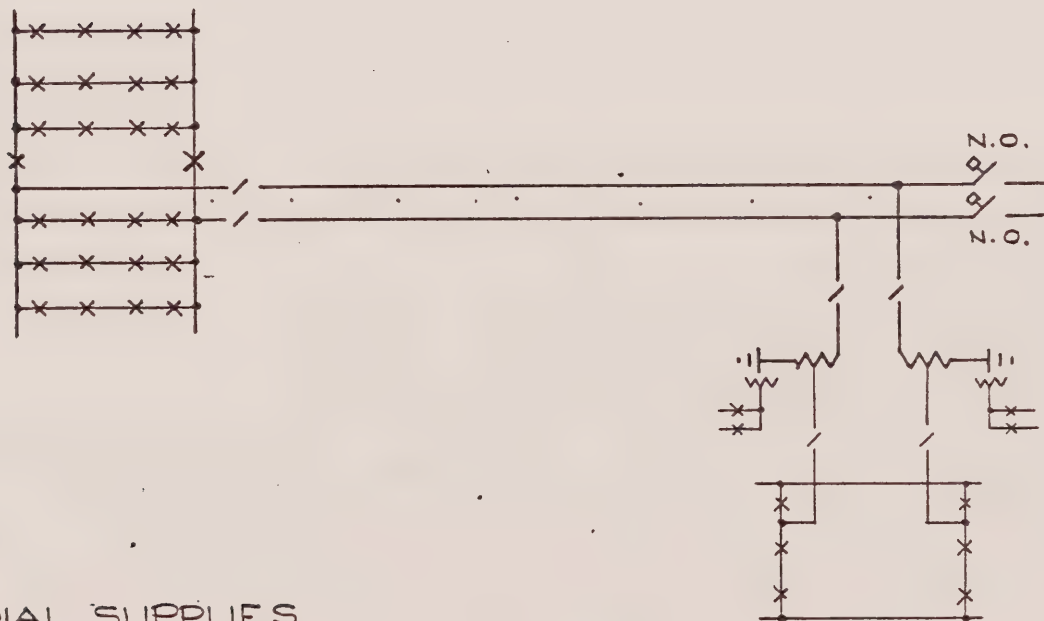
FIGURE·9

RADIAL SUPPLIES
LINE WITH 1 AUTOTRANSFORMER

FIGURE·10

NUMBER OF BREAKERS TRIPPED TO CLEAR FAULTS
FIGURE 9 & 10
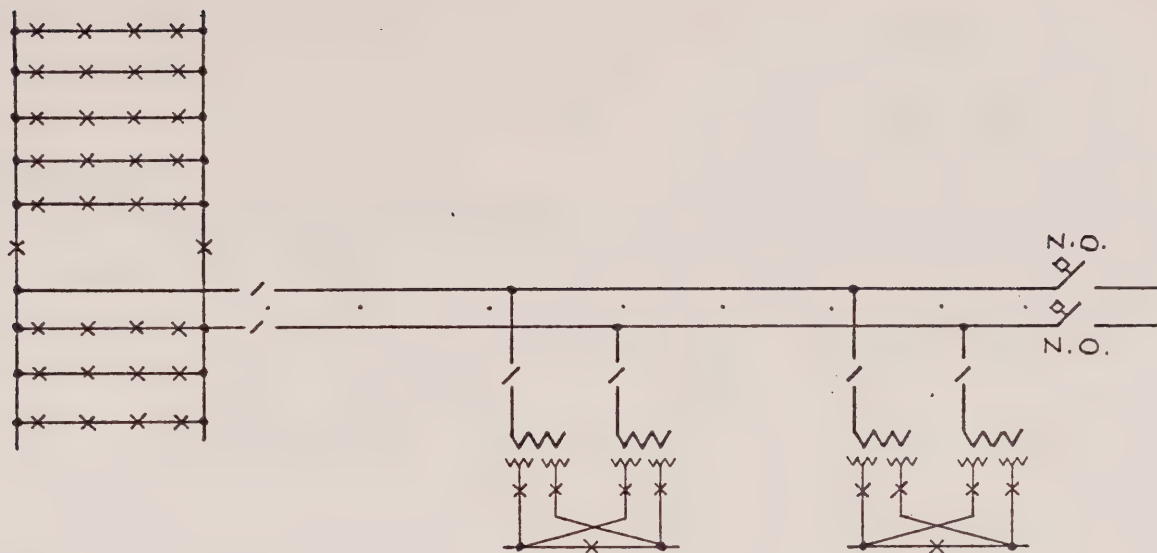
RADIAL SUPPLIES
LINE WITH 2 STEPDOWNS
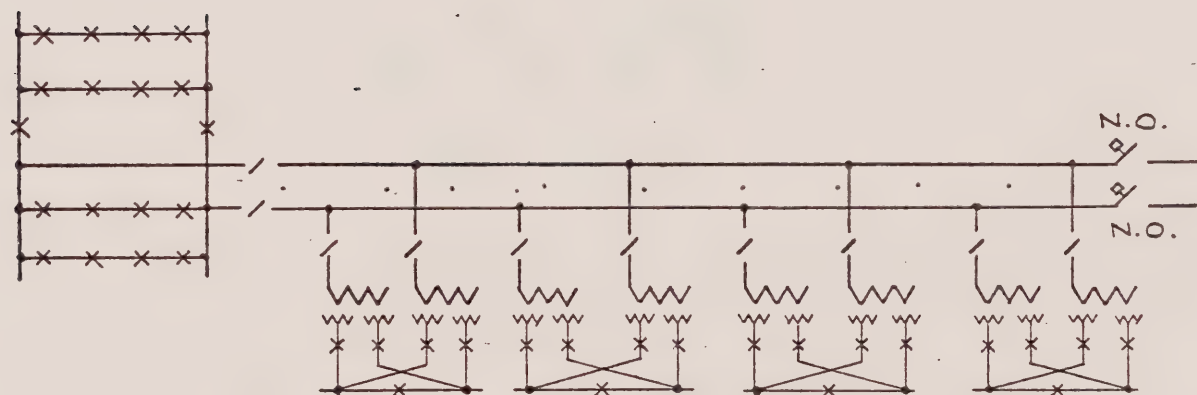
FIGURE·11

RADIAL SUPPLIES
LINE WITH 4 STEPDOWNS

FIGURE·12

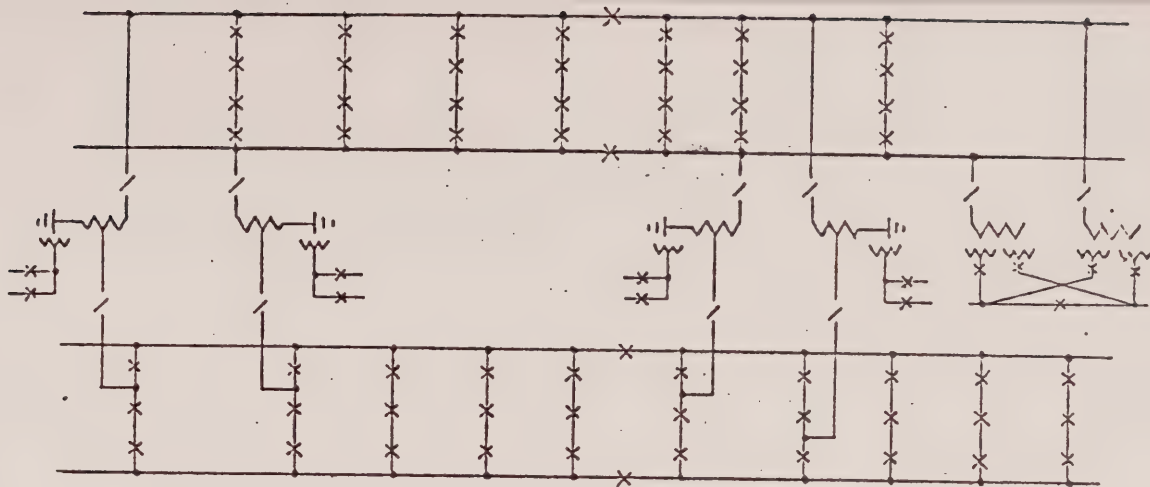# NUMBER OF BREAKERS TRIPPED TO CLEAR FAULTS
FIGURE 11 & 12
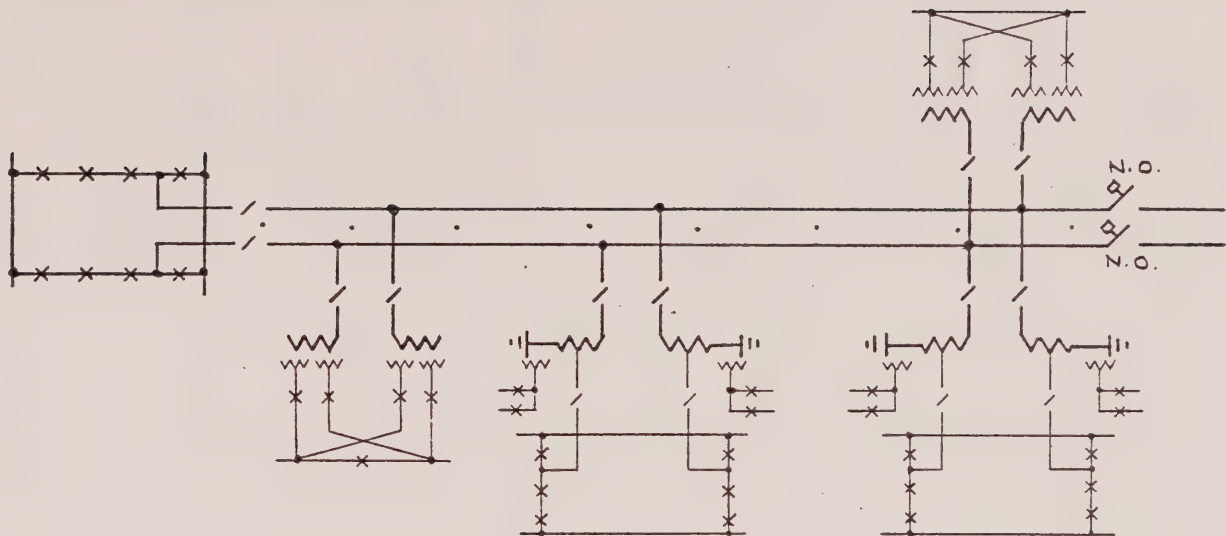
RADIAL SUPPLIES
LINE WITH TWO AUTOS & 2 STEPDOWNS

FIGURE · 13

N.O.

N.O.
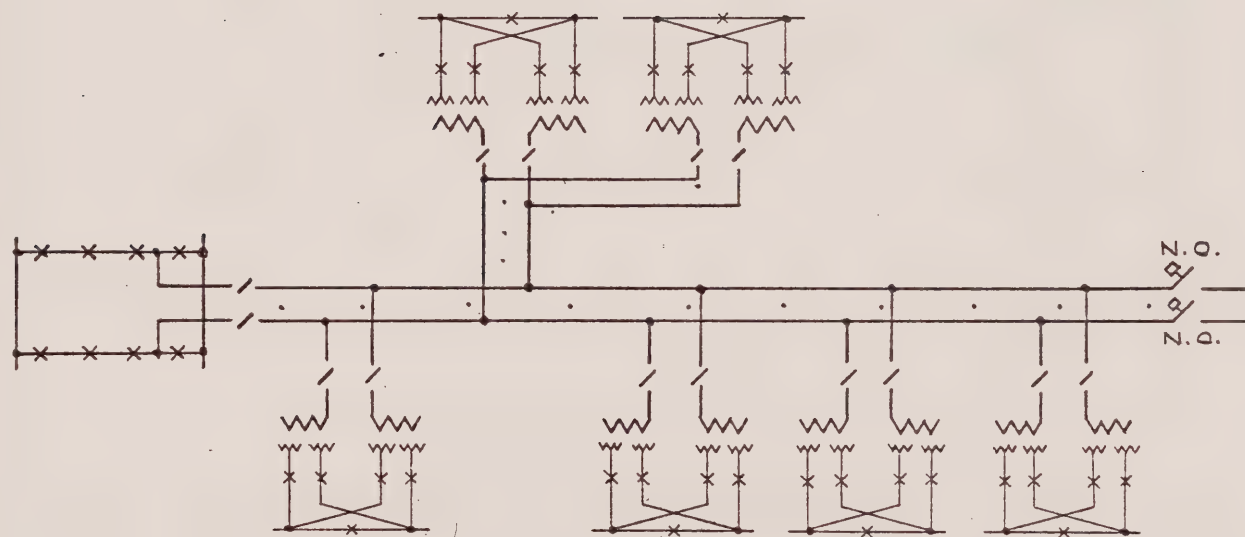
RADIAL SUPPLIES
LINE WITH 6 STEPDOWNS

FIGURE · 14

N.O.

N.O.

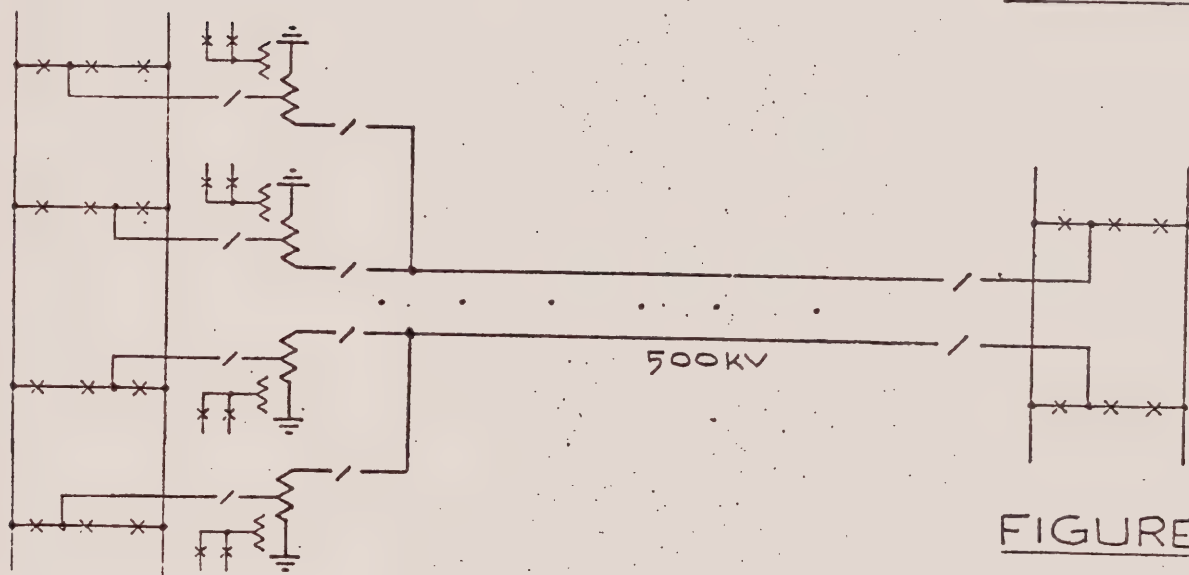NUMBER OF BREAKERS TRIPPED TO CLEAR FAULTS
FIGURE 13 & 14

FIGURE ·15

500KV

FIGURE·16

NUMBER OF BREAKERS TRIPPED TO CLEAR FAULTS

FIGURE 15 & 16

Approximately 2½ seconds after the initiating event, 210 MW of generation was rejected at Moses - St. Lawrence. This was due to the tripping of the second Moses - Adirondack - Porter line.

Three Ontario transformer stations, Belleville, Havelock and Oshawa-Wilson, with a total customer load of 183 MW, were automatically interrupted with the transmission tripping.

The estimated pre-disturbance loading of the Ontario transmission at the separation points was 720 MW towards the Toronto area and for the New York transmission 530 MW to the south and east. Immediately following separation the island was in a overgenerated state.

Subsequent Events

Large frequency oscillations from 58.8 to 64.5 Hz were reported in the island. FTR (frequency trend relay) operation occurred in eastern Ontario and under-frequency relays operated in New York State. This operation interrupted an additional 361 MW of Ontario, 17 MW of Niagara Mohawk and 6 MW of New York State Electric & Gas customer load.

107 MW of Niagara Mohawk's hydro generation and 3 MW of New York State Electric & Gas's hydro generation was lost.

Further generation reduction in the island, including governor action, took place. Saunders and Moses - St. Lawrence GS's with pre-disturbance outputs of 820 MW and 850 MW respectively, were reduced to a very low level for a short time. Hydro Quebec generation radially connected to Ontario was reduced by governor action.

The only thermal unit in the island was Ontario's Lennox GS #2 unit, 500 MW capacity, with a pre-disturbance output of 125 MW. Severe swings were observed and the unit was tripped manually by 23.10.

As a result of the system split and generation deficiency in Ontario, a power change relay located at Kenora, the Ontario terminal of the Manitoba - Ontario tie lines, correctly operated to trip the ties. This operation, in turn, correctly resulted in tripping the Manitoba - North Dakota tie. The pre-disturbance flow from Manitoba was 220 MW to Ontario and 120 MW to North Dakota, thus an additional 340 MW deficiency to the continental grid resulted.

The effective generation loss to the main continental grid was approximately 1590 MW, made up as follows:

N.Y. State flow south and east at separation points	530 MW
Ontario flow West at separation points	720 MW
Manitoba flow to Ontario	220 MW
Manitoba flow to North Dakota	120 MW
Total	1590 MW

The grid frequency as recorded at Ontario's Richview station dropped from 59.985 to 59.945 Hz.

Restoration in Ontario

The eastern Ontario - Northern New York island was re-synchronized to the main system via circuit H24C (Hinchinbrooke - Cherrywood) at 23.14 (6 min.) following an unsuccessful attempt with circuit A29C at 23.13. Restoration of the remaining circuits followed and customer load pickup orders were issued.

All circuit restoration, 230 and 115 kV, was completed by 23.23 (15 min.) and most of the customer load was restored by this time.

The Manitoba - North Dakota tie, Y20P, was restored by Manitoba at 23.12 (4 min.) and the Ontario - Manitoba ties placed on load at 23.16 (8 min.) and 23.20 (10 min.).

Ontario's area requirement was returned to zero at 23.16 (8 min.) and the grid frequency had returned to 59.985 Hz (pre-disturbance value) at this time.

Restoration in New York State

Once Ontario Hydro re-established ties between the isolated island and the remainder of their system, Niagara Mohawk, at 23.14, closed the two 115 kV Browns Falls - Taylorville circuits re-establishing a connection from Northern to Central New York. At 23.16, the 230 kV circuit, Adirondack - Porter 11, was placed in service re-establishing the 230 kV path from Northern to Central New York. At 23.25, the Plattsburg - Sand Bar 115 kV tie to Vermont was also closed. By 23.29, all Niagara Mohawk switching stations were back to normal with most customer load restored. New York State Electric & Gas load was restored within 30 seconds after tripping.

EXAMPLES OF THE APPLICATION OF PROBABILITY THEORY
TO RELIABILITY PROBLEMS

Example 1 - The Benefits of Redundancy

A load is to be supplied by a single generator and a single transmission line. The line can be either a one-circuit line or a two-circuit line with each circuit able to carry the full generator output. The problem is to determine the reliability of the two alternatives.

A schematic diagram of this arrangement and the assumed characteristics are shown on Figure 10-M-1.

a) Single-Circuit Transmission Line

One can consider the combination of line and generator as a single device. The load will only be served when both the generator and the line are in service hence the failure rate of this device will be the sum of the failure rates of the line and the generator ($\lambda c = \lambda_T + \lambda_G = 7$). The average repair time of the combination will be:-

$$r_c = \frac{\lambda_T \times r_T + \lambda_G \times r_G}{\lambda_T + \lambda_G} = \frac{(3 \times 12 + 4 \times 44.7)}{(3 + 4)} = 30.7 \text{ hours/event.}$$

It must be noted that failure rates and repair times are obtained by taking the average of many similar occurrences. The results of the calculations must be interpreted similarly. A repair time of 30.7 hours means that over the years the average repair time is expected to be 30.7 hours. The probability of not having power at the load bus:-

$$p = \frac{\lambda}{\lambda + 8760/r} = \frac{7}{7 + 285.47} = .0239$$

A better reliability index is the expected energy
not supplied. This is the product of the above probability,
the size of the load, and the hours in the year. In our
example this would be 0.0239 x 100 MW x 8760 hr. = 20936 MWhrs
per year.

Customers are also affected by the frequency of
interruptions. The frequency of interruptions is given
by f = p/r = .0239 x 285.47 = 6.85/year.

b)   Double Circuit Transmission Line

Since the added circuit is fully redundant both circuits
must be out of service at the same time or the generator
must fail before the supply is interrupted. The liklihood
of two circuits out simultaneously is lower than that for
a single-circuit line.

Techniques are available to compute the equivalent
line outage rate and repair time for the 2-cct. line.
Assuming the outages on each circuit are independent, the
failure rate of the line is reduced from 3.0 to 0.0245/yr.,
while the average repair time becomes 6 hours.

When this line model is combined with the generator
model as in example 1-a, the generator outage will dominate
the picture. Comparable indices are shown in the following
interruption table:-

	Interruption Frequency	Interruption Duration	Expected Energy Not Supplied (MWH)
1. Circuit Line	6.83/yr	30.7 hrs.	20936
2. Circuit Line	3.94/yr	44.5 hrs.	17520

The average interruption duration, now dominated by the generator, has increased compared with the single circuit transmission line combination. On the other hand, the frequency of interruption is much reduced and so is the energy not delivered.

The above example does not take into account all the factors affecting reliability, even for this simplified system.

Example 2 - The Benefits of a Spare Element

A 600 MW generator is to be connected to the power system by a step-up transformer. The problem is to determine the reliability of two alternatives:-

a) Three single-phase transformers rated 200 MW each
b) As above and with one spare transformer available which can be installed if one of the 3 single-phase units fail.

The transformer failure rate is 0.02/year, repair time is 8 months and installation time is 24 hours.

The first alternative is a simple operating/non-operating case. The outage rate per transformer must be multiplied by 3 (because there are 3 transformers) to get the equivalent outage rate and the repair time is 8 months plus 1 day (for installation). It can be shown that the probability that the connection between the generator and the system will be unavailable is 0.0386. The expected energy not delivered for one year will be 0.0386 x 600 x 8760 = 202881 MWhrs.

Adding a spare transformer makes the case considerably more complex from a reliability point of view. Figure 10-M-2 shows the various states which the step-up transformer can be in. Arrows denote a transition from one state to another. The transition rate is indicated above the arrows.

Beginning in state N, the step-up transformer is operating and 1 spare transformer is available. Failure of a single-phase transformer causes the step-up transformer to go to state SF. Transfers to state S by repair of the faulty transformer or to state F by installation of the spare transformer are both possible. While in state F the failure of one of the operating single-phase transformers will change the step-up transformer to FF, the state with 2 failed single-phase transformers.

It is assumed that there is no lack of repair facilities or manpower to effect the repair work. Transfer from state FF to state SF will occur when one single-phase transformer is repaired. A direct transfer from FF to S could occur if 2 repair jobs were completed simultaneously. Although theoretically possible, the transition rate is so low that neglecting this transition will not change the results. The above process can be considered a Markov chain process. The individual state probabilities are found by solving the transition intensity matrix equation which may be derived from the model shown in Figure 10-M-2. Solution of this equation yields the following long-term probabilities:-

$$P_N = \left\{ 2\,\mu_s^2\,u_r^2 + 2\mu_s\,\mu_r^2\,(3\lambda + \mu_r) \right\} / A$$

$$P_F = 6\,\lambda\mu_s^2\,\mu_r / A$$

$$P_{FF} = 9\,\lambda^2\mu_s^2 / A$$

$$P_{SF} = \left\{ 6\,\lambda\mu_s\mu_r\,(3\lambda + \mu_r) \right\} / A$$

$$P_S = \left\{ 6\,\lambda\mu_r^2\,(3\lambda + \mu_r) \right\} / A$$

$$\text{With } A = 9\lambda^2\mu_s^2 + 2\mu_r \left\{ (\mu_s + \mu_r)\ (3\lambda + \mu_r)\ (3\lambda + \mu_s) \right\}$$

Details of the method are explained in modern textbooks; see for example Reference 13.

Substituting values for the characteristics in the equations produces a value of 0.99907 for the sum of P_F and P_N, the probability that the step-up transformer will be available.

The expected energy not delivered will be (1-0.99907) x 600 x 8760 = 4888 MWhrs per year.

Adding the spare bank has reduced the expected energy not delivered by a factor of 40.

(a) Simple generation - transmission system
    with single circuit transmission line.

(b) Generation - transmission system with
    double circuit transmission line.

λ = failure rate (failures per unit time)

r = repair time

c_G = unit capacity.

LOAD = 100 MW

λ_G = 4/year

λ_T = 3/year

λ_{T1} = λ_{T2} = 3/year

r_G = 44.7 hours

r_T = 12 hours

r_{T1} = r_{T2} = 12 hours

Figure 10-M-1
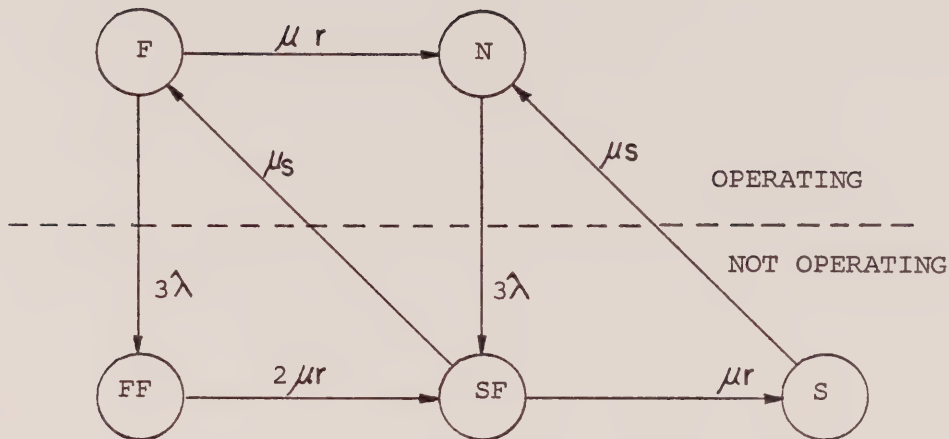
MARKOV MODEL FOR THREE SINGLE-PHASE
TRANSFORMERS WITH ONE SPARE

λ = failure rate (failures per unit time)

μr = repair rate (inverse of repair time)

μs = installation rate (inverse of installation time.

TRANSFORMER BANK OPERATING STATES:-

(N) spare unit available

(F) no spare unit available, first failed unit under repair.

TRANSFORMER BANK NON-OPERATING STATES:

(SF) one unit broken down, spare unit available.

(S) broken down unit repaired, spare unit also available.

(FF) spare unit broken down, first failed unit not yet repaired.

Figure 10 - M - 2

TYPICAL ITEMS OF COMPONENT DATA NOW BEING COLLECTED
BY ONTARIO HYDRO

        The following is a partial listing of the detailed
information kept concerning outages on the Bulk Power Trans-
mission System:

1.0 FORCED OUTAGES

     1.1 Component Identification

     1.1.1 Design Voltage Class and Operating Voltage Class

     1.1.2 Component Type Classification
                  - bus
                  - line or cable
                  - circuit breaker
                  - transformer (including phase shifters)

     1.1.3 Geographical Region

     1.1.4 Property Number (line section)

     1.1.5 Operating Designation

     1.2 Date and Time

     1.3 Total Outage Time

     1.4 Type of Outage

     1.4.1 Automatic

     1.4.2 Manual - unavoidable, undeferable
                   - deferable or deferred

     1.4.3 Extended - unavoidable
                     - deferable

     1.7 Fault Data

     1.7.1 Phases Involved (BØ-WØ-BG-WG etc.)
                  - external
                  - no fault

1.0 FORCED OUTAGES

     1.8 Reclosing Performance

     1.8.1 Line Test

     1.8.2 Lockouts

     1.8.3 Successful reclosures and type and timing

     1.9 Cause of Outage (see note #1)

     1.10 Effects of Outage, Including Effects of Associated
           Outages

           (see note #2)

     1.11 Weather

     1.12 Generation Rejection

     1.12.1 Date, Time, Location, Reason (Legitimate, Personnel,
              Communications Malfunction, Relay Malfunction)

2.0 FORCED ASSOCIATED OUTAGES

     2.1 Component Identification

     2.2 Date and Time

     2.3 Total Outage Duration

     2.4 Cause

3.0 SCHEDULED OUTAGES

     3.1 Component Identification
         Same as 1.1

     3.2 Date and Time

     3.3 Total Outage Time

     3.4 Requesting Department

     3.5 Reason for Outage

4.0 ASSOCIATED SCHEDULED OUTAGES

    4.1 Components Identification (as in 1.1)

    4.2 Date and Time

    4.3 Reason

NOTES

1. The following is a detailed listing of the data
    under the category "Cause of Outage".

    Equipment Initiating Component Outage

        - Bus
        - Breaker
        - Power Transformer
        - Tap Changer
        - Current Transformers
        - Potential Transformer
        - Capacitive Voltage Transformer
        - Wave Trap
        - Surge Arrester
        - Arc Gaps
        - Disconnect Switch
        - Insulator
        - Bushing
        - Ground Switch
        - Miscellaneous Station Equipment
        - Line Equipment
        - Cable
        - Cable Pothead
        - Relays
        - Power Line Carrier
        - Microwave System
        - Supervisory Control Facilities
        - Landline

    Department or Group Responsible for Equipment

        - LMD
        - SMD
        - Forestry
        - Operating
        - P & C
        - Foreign System
        - Customer

APPENDIX

NOTES (Continued)

Nature of Defect

- Housing Failure
- Primary Winding Failure
- Tertiary Winding Failure
- Secondary Winding Failure
- Operating Mechanism Failure
- Mechanical Defect
- Oil Contamination
- Oil or Gas Leak
- Internal Explosion or Flash
- Cooling System Trouble
- Flashover
- Open Phase
- Drop Lead
- Phase Discrepancy
- Corrosion
- Overload
- Footing Failure
- Anchor Failure
- Guy Assembly Failure
- Main Support Failure
- Cross Braces Failure
- Cross Arm Failure
- Sagging
- Sleeve Failure
- Damper Failure
- Spacer Failure
- Dead End Connection Failure
- Suspension Clamp Failure
- Skywire Clamp Failure
- Galloping
- Cable Joint Failure
- Cable Sheath Failure
- Cable Pipe Failure
- Cable Jacket/Covering Failure
- Cable Bonding Failure
- Cable Cathodic Protection Failure
- Cable Pumping Plant Failure
- Compressed Air Supply Failure
- Design Problem
- Intermediate Wiring Trouble
- A.C. Power Supply
- D.C. Power Supply
- Electronic Defect
- Setting

NOTES (Continued)

Foreign Interference

- Ground Vehicles/Kites
- Birds, Animals
- Fallen Tree
- Tree or Bush
- Flying Debris, Fire
- Landslide, Flooding
- Sabotage, Digging

Personnel Error

- Interference
- Switching
- Procedure

Trouble External to Components
- Reason for Component Outage

- Instability
- Backup Operation

APPENDIX 10-0

COMPOSITE SYSTEM RELIABILITY PROGRAMS

A.   PCAP

The Power Technologies Incorporated Fast Contingency
Analysis Program (PCAP) which is being developed by P.T.I.
under contract with the Northeast Power Co-ordinating
Council, represents one of the more recent attempts on
the part of the industry to find a method to examine overall
system reliability in a practical and efficient way.

Some idea of the requirement for computational efficiency
can be gathered from a small system with only 60 components
(lines, generators, transformers). If the system were to be
investigated exhaustively, that is considering every possible
outage and combination of outages, 2^{60} or approximately 10^{18}
situations would require evaluation. Even for modern com-
puters this is a formidable and expensive job. Any practical
method for assessing reliability must reduce the number of
situations to a more manageable level, without losing signi-
ficant accuracy.

PCAP embodies new developments which greatly reduce the
number of studies required to assess reliability of the
power system. The extent of the reduction is a function of
the system configuration and loading so that it is difficult
to anticipate the amount of work required.

PCAP uses a rapid direct current load flow technique
to simulate the system conditions for each outage event
considered. The technique greatly reduces computation time
but does not provide any knowledge of system voltages or
reactive requirements. PCAP is thus able to provide a
reasonable simulation of overload problems but does not
identify voltage problems.

A brief description of the overall application of
PCAP follows:-

1. The user inputs the system electrical parameters
   (loads, generator ratings and initial loading,
   line and transformer ratings and reactances),
   the outage data for each element, a list of
   specified outages, the number of program-chosen
   outages, and certain additional control infor-
   mation.

2. The program performs a generation-load study similar to the Loss of Load calculation and prints the appropriate indices.

3. The program then simulates the system under the condition with all the facilities in service.

4. Providing there are no problems in the preceding simulation, the program performs analyses to determine outages in order of severity.

5. The program then considers all user-specified outages, one at a time, checking for load isolations, generation shortages, and element overloads. The program then considers the effect of outages taken two at a time.

6. The program accumulates data concerning the probability and frequency with which facilities are overloaded or islands are isolated (generation alone, load and generation, or load alone) and tabulates the expected load not served and computes an index related to the frequency and magnitude of load interruptions. These are summarized and printed.

Work is continuing to develop PCAP so that in the future it may provide a more realistic and comprehensive measure of system reliability. The logic and some of the concepts involved in the program are complex and progress is consequently slow, despite the considerable effort being expended.

B.   Work by Ontario Hydro Research Staff

Ontario Hydro's Research Division is developing a composite system reliability program which employs a load flow technique wherein both the real and reactive aspects of the system are modelled using linear approximations. If this work is successful it will enable consideration of voltage as a criterion for system failures and further extend the ability to perform system reliability analyses.